UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2019 or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

001-3034
(Commission File Number)

Xcel Energy Inc.
(Exact name of registrant as specified in its charter)

Minnesota	**41-0448030**
(State or Other Jurisdiction of Incorporation or Organization)	(IRS Employer Identification No.)
414 Nicollet Mall Minneapolis Minnesota	**55401**
(Address of Principal Executive Offices)	(Zip Code)

612 330-5500
(Registrant's Telephone Number, Including Area Code)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol	Name of each exchange on which registered
Common Stock, $2.50 par value	XEL	Nasdaq Stock Market LLC

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. ☒ Yes ☐ No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. ☐ Yes ☒ No

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. ☒ Yes ☐ No

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). ☒ Yes ☐ No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act. ☒ Large accelerated filer ☐ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐ Emerging growth company

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). ☐ Yes ☒ No

As of June 28, 2019, the aggregate market value of the voting common stock held by non-affiliates of the Registrant was $30,629,347,167 and there were 514,865,476 shares of common stock outstanding.

As of Feb. 13, 2020, there were 524,669,024 shares of common stock outstanding, $2.50 par value.

DOCUMENTS INCORPORATED BY REFERENCE

The Registrant's definitive Proxy Statement for its 2020 Annual Meeting of Shareholders is incorporated by reference into Part III of this Form 10-K.

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PART I

ITEM 1 — BUSINESS

Definitions of Abbreviations

Xcel Energy Inc.'s Subsidiaries and Affiliates (current and former)

Capital Services	Capital Services, LLC
Eloigne	Eloigne Company
e prime	e prime inc.
NSP-Minnesota	Northern States Power Company, a Minnesota corporation
NSP System	The electric production and transmission system of NSP-Minnesota and NSP-Wisconsin operated on an integrated basis and managed by NSP-Minnesota
NSP-Wisconsin	Northern States Power Company, a Wisconsin corporation
Operating companies	NSP-Minnesota, NSP-Wisconsin, PSCo and SPS
PSCo	Public Service Company of Colorado
SPS	Southwestern Public Service Co.
Utility subsidiaries	NSP-Minnesota, NSP-Wisconsin, PSCo and SPS
WGI	WestGas InterState, Inc.
WYCO	WYCO Development, LLC
Xcel Energy	Xcel Energy Inc. and its subsidiaries

Federal and State Regulatory Agencies

CPUC	Colorado Public Utilities Commission
D.C. Circuit	United States Court of Appeals for the District of Columbia Circuit
DOC	Minnesota Department of Commerce
DOE	United States Department of Energy
DOT	United States Department of Transportation
EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
Fifth Circuit	United States Court of Appeals for the Fifth Circuit
IRS	Internal Revenue Service
Minnesota District Court	U.S. District Court for the District of Minnesota
MPSC	Michigan Public Service Commission
MPUC	Minnesota Public Utilities Commission
NDPSC	North Dakota Public Service Commission
NERC	North American Electric Reliability Corporation
NMPRC	New Mexico Public Regulation Commission
NRC	Nuclear Regulatory Commission
OAG	Minnesota Office of the Attorney General
PHMSA	Pipeline and Hazardous Materials Safety Administration
PSCW	Public Service Commission of Wisconsin
PUCT	Public Utility Commission of Texas
SDPUC	South Dakota Public Utilities Commission
SEC	Securities and Exchange Commission
TCEQ	Texas Commission on Environmental Quality

Electric, Purchased Gas and Resource Adjustment Clauses

CIP	Conservation improvement program
DCRF	Distribution cost recovery factor
DSM	Demand side management
DSMCA	Demand side management cost adjustment
ECA	Retail electric commodity adjustment
EECRF	Energy efficiency cost recovery factor
FCA	Fuel clause adjustment
FPPCAC	Fuel and purchased power cost adjustment clause
GCA	Gas cost adjustment
GUIC	Gas utility infrastructure cost rider
PCCA	Purchased capacity cost adjustment
PCRF	Power cost recovery factor
PGA	Purchased gas adjustment
PSIA	Pipeline system integrity adjustment
RDF	Renewable development fund
RER	Renewable energy rider
RES	Renewable energy standard
RESA	Renewable energy standard adjustment
SCA	Steam cost adjustment
SEP	State energy policy rider
TCA	Transmission cost adjustment
TCR	Transmission cost recovery adjustment
TCRF	Transmission cost recovery factor

Other

ADIT	Accumulated deferred income taxes
AFUDC	Allowance for funds used during construction
ARO	Asset retirement obligation
ASC	FASB Accounting Standards Codification
ASU	FASB Accounting Standards Update
BART	Best available retrofit technology
Boulder	City of Boulder, CO
C&I	Commercial and Industrial
CACJA	Clean Air Clean Jobs Act
CAISO	California Independent System Operator
CapX2020	Alliance of electric cooperatives, municipals and investor-owned utilities in the upper Midwest involved in a joint transmission line planning and construction effort
CBA	Collective-bargaining agreement
CCR	Coal combustion residuals
CCR Rule	Final rule (40 CFR 257.50 - 257.107) published by the EPA regulating the management, storage and disposal of CCRs as a nonhazardous waste
CDD	Cooling degree-days
CEO	Chief executive officer
CFO	Chief financial officer
CEP	Colorado Energy Plan
CIG	Colorado Interstate Gas Company, LLC
CPCN	Certificate of public convenience and necessity
CWA	Clean Water Act
CWIP	Construction work in progress
DECON	Decommissioning method where radioactive contamination is removed and safely disposed of at a requisite facility or decontaminated to a permitted level.
DRC	Development Recovery Company
DRIP	Dividend Reinvestment Program
EEI	Edison Electric Institute
ELG	Effluent limitations guidelines
EMANI	European Mutual Association for Nuclear Insurance
EPS	Earnings per share
EPU	Extended power uprate
ETR	Effective tax rate
FASB	Financial Accounting Standards Board
FTR	Financial transmission right
GAAP	Generally accepted accounting principles
GE	General Electric
GHG	Greenhouse gas

HDD	Heating degree-days
IM	Integrated market
IPP	Independent power producing entity
IRP	Integrated Resource Plan
ITC	Investment Tax Credit
JOA	Joint operating agreement
LSP Transmission	LSP Transmission Holdings, LLC
MDL	Multi-district litigation
MEC	Mankato Energy Center
MGP	Manufactured gas plant
MISO	Midcontinent Independent System Operator, Inc.
Moody's	Moody's Investor Services
NAAQS	National Ambient Air Quality Standard
Native load	Demand of retail and wholesale customers that a utility has an obligation to serve under statute or contract
NAV	Net asset value
NEIL	Nuclear Electric Insurance Ltd.
NOI	Notice of Inquiry
NOL	Net operating loss
O&M	Operating and maintenance
OATT	Open Access Transmission Tariff
PI	Prairie Island nuclear generating plant
Post-65	Post-Medicare
PPA	Purchased power agreement
Pre-65	Pre-Medicare
PTC	Production tax credit
REC	Renewable energy credit
ROE	Return on equity
ROFR	Right-of-first-refusal
ROU	Right-of-use
RPS	Renewable portfolio standards
RTO	Regional Transmission Organization
Standard & Poor's	Standard & Poor's Ratings Services
SERP	Supplemental executive retirement plan
SMMPA	Southern Minnesota Municipal Power Agency
SO_2	Sulfur dioxide
SPP	Southwest Power Pool, Inc.
TCEH	Texas Competitive Energy Holdings
TCJA	2017 federal tax reform enacted as Public Law No: 115-97, commonly referred to as the Tax Cuts and Jobs Act
THI	Temperature-humidity index
TOs	Transmission owners
TransCo	Transmission-only subsidiary
TSR	Total shareholder return
VaR	Value at Risk
VIE	Variable interest entity
WOTUS	Waters of the U.S.

Measurements

Bcf	Billion cubic feet
KV	Kilovolts
KWh	Kilowatt hours
MMBtu	Million British thermal units
MW	Megawatts
MWh	Megawatt hours

Forward-Looking Statements

Except for the historical statements contained in this report, the matters discussed herein are forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements, including the 2020 EPS guidance, long-term EPS and dividend growth rate, as well as assumptions and other statements are intended to be identified in this document by the words "anticipate," "believe," "could," "estimate," "expect," "intend," "may," "objective," "outlook," "plan," "project," "possible," "potential," "should," "will," "would" and similar expressions. Actual results may vary materially. Forward-looking statements speak only as of the date they are made, and we expressly disclaim any obligation to update any forward-looking information.

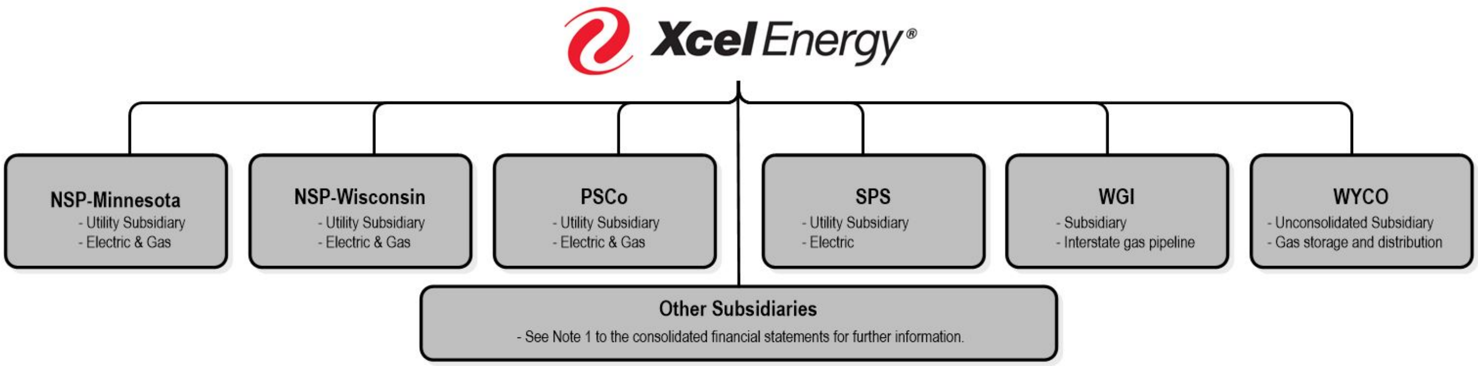
The following factors, in addition to those discussed elsewhere in this Annual Report on Form 10-K for the fiscal year ended Dec. 31, 2019 (including the items described under Factors Affecting Results of Operations; and the other risk factors listed from time to time by Xcel Energy Inc. in reports filed with the SEC, including "Risk Factors" in Item 1A of this Annual Report on Form 10-K hereto), could cause actual results to differ materially from management expectations as suggested by such forward-looking information: operational safety, including our nuclear generation facilities; successful long-term operational planning; commodity risks associated with energy markets and production; rising energy prices and fuel costs; qualified employee work force and third-party contractor factors; ability to recover costs, changes in regulation and subsidiaries' ability to recover costs from customers; reductions in our credit ratings and the cost of maintaining certain contractual relationships; general economic conditions, including inflation rates, monetary fluctuations and their impact on capital expenditures and the ability of Xcel Energy Inc. and its subsidiaries to obtain financing on favorable terms; availability or cost of capital; our customers' and counterparties' ability to pay their debts to us; assumptions and costs relating to funding our employee benefit plans and health care benefits; our subsidiaries' ability to make dividend payments; tax laws; effects of geopolitical events, including war and acts of terrorism; cyber security threats and data security breaches; seasonal weather patterns; changes in environmental laws and regulations; climate change and other weather; natural disaster and resource depletion, including compliance with any accompanying legislative and regulatory changes; and costs of potential regulatory penalties.

Where to Find More Information

Xcel Energy's website address is www.xcelenergy.com. Xcel Energy makes available, free of charge through its website, its annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 as soon as reasonably practicable after the reports are electronically filed with or furnished to the SEC. The SEC maintains an internet site that contains reports, proxy and information statements, and other information regarding issuers that file electronically at http://www.sec.gov.

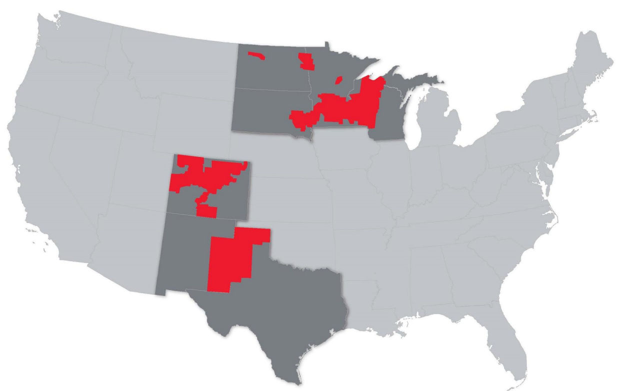
Overview

Xcel Energy is a major U.S. regulated electric and natural gas delivery company headquartered in Minneapolis, Minnesota (incorporated in Minnesota in 1909). The Company serves customers in eight mid-western and western states, including portions of Colorado, Michigan, Minnesota, New Mexico, North Dakota, South Dakota, Texas and Wisconsin. Xcel Energy provides a comprehensive portfolio of energy-related products and services to approximately 3.7 million electric customers and 2.1 million natural gas customers through four utility subsidiaries (i.e., NSP-Minnesota, NSP-Wisconsin, PSCo and SPS). Along with the utility subsidiaries, the transmission-only subsidiaries, WYCO (a joint venture formed with CIG to develop and lease natural gas pipelines, storage and compression facilities) and WGI (an interstate natural gas pipeline company) comprise the regulated utility operations. The Company's significant nonregulated subsidiaries are Eloigne, Capital Services and Nicollet Holdings.



Utility Subsidiaries' Service Territory

Electric customers	3.7 million
Natural gas customers	2.1 million
Total assets	$50.4 billion
Electric generating capacity	18,730 MW
Electric transmission lines (conductor miles)	108,238 miles
Electric distribution lines (conductor miles)	207,524 miles
Natural gas transmission lines	2,177 miles
Natural gas distribution lines	35,624 miles
Natural gas storage capacity	53.4 Bcf

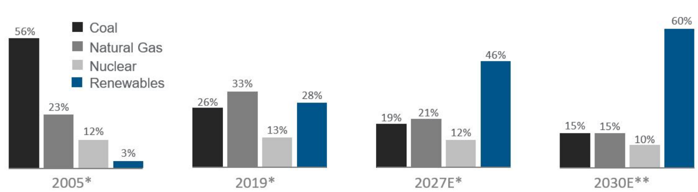


Vision, Mission and Values

Lead the Clean Energy Transition

For more than a decade, Xcel Energy has proactively managed the risk of climate change and increasing customer demand for renewable energy through a clean energy strategy that consistently seeks to reduce carbon emissions and aims to transition our operations for the future. We have successfully reduced our carbon emissions from generation serving our customers by nearly 44% from 2005 to 2019 and we are on track to reach 60% renewable generation by 2030. We expect to reduce our carbon footprint by 80% by 2030 (over 2005 levels) and aspire to serve all customers with 100% carbon-free electricity by 2050.

Energy Mix – 80% Carbon Reduction by 2030



* Remaining includes hydro, biomass and other sources; future-year estimates dependent on various factors
** Potential scenarios that achieve carbon reduction goal

In addition to increasing our renewable generation, Xcel Energy is transitioning how we produce, deliver and encourage the efficient use of energy by:

- Offering energy efficiency programs;
- Retiring coal units and modernizing generating plants; and
- Advancing power grid capabilities.

We are working to add over 4,700 MW of wind energy to our system by 2021, including 3,500 MW of owned wind and 1,200 MW of PPAs. Of the 3,500 MW of owned wind, 1,300 MW are now in service and 2,200 MW are under development or construction. This will bring our total wind capacity to over 11,000 MW by 2021.

Our long-term plan includes the addition of approximately 5,000 MW of solar energy by the early 2030s, 275 MW of battery storage and a potential ten-year extension of our Monticello nuclear plant. It also includes the retirement of multiple coal units totaling approximately 2,000 MW. Xcel Energy plans to continue to evaluate its coal fleet for other potential early retirements as part of state resource plans or other regulatory proceedings.

Enhance the Customer Experience

Customers' energy expectations continue to evolve and Xcel Energy is committed to providing the options and solutions they want and value.

Xcel Energy continues to expand its renewable energy production and offerings, and further develop and promote DSM and conservation programs. Over the past decade, the Company has spent over $2.1 billion on these programs.

We are also in the process of transforming our electric grid to accommodate increased levels of renewables, distributed energy resources and corresponding data growth, while maintaining high levels of reliability and security.

We have partnered with policymakers, state agencies and innovative companies to develop nation-leading electric vehicle solutions for our customers. We are preparing for a substantial amount of electric vehicles on roads across our service territory by 2030 and are focused on providing helpful information, making installations simple and keeping customer bills affordable through new rates and programs. We anticipate offering innovative programs for electric vehicle customers in Minnesota, Wisconsin, and Colorado this year. We are filing comprehensive Transportation Electrification Plans in both Colorado and New Mexico in the coming year.

We continue to develop and deliver new renewable energy solutions for our residential and C&I customers who want more directly sourced energy. Through programs such as Renewable*Connect® and Windsource®, we match our customers' needs without them needing to add expensive or on-site equipment.

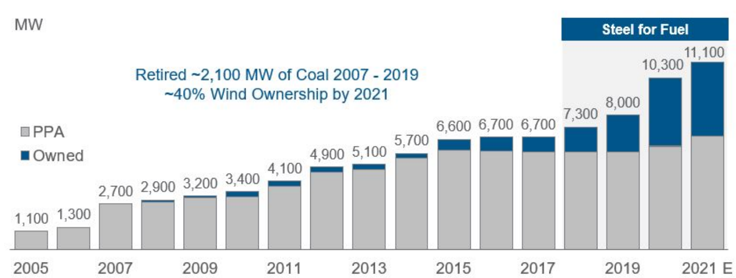
Keep Bills Low

Affordability is critical part of our customers' experience. We are focused on the impact our operations, regulation and legislation have on their bills. Our objective is to keep bill increases at or below the rate of inflation.

Our utility service territories benefit from the geographic concentration of favorable renewable resources. Strong wind and high solar generation capacity factors lower the lifetime cost of these resources. This, coupled with renewable tax credits and avoided fuel costs, enables us to invest in more renewable generation, in which the capital costs are largely or completely offset by fuel savings. We call this our "Steel for Fuel" strategy.

Steel for Fuel not only expands the Company's renewable portfolio, but allows delivery of carbon-free energy without raising customer bills through replacement of fossil fuel generation or fuel-free wind and solar.

Changing Composition of Wind Capacity



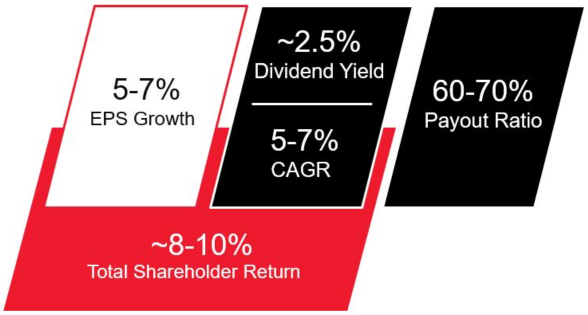
Xcel Energy is working to keep long-term O&M expense relatively flat without compromising reliability or safety. We intend to accomplish this objective by continually improving processes, leveraging technology, proactively managing risk and maintaining a workforce prepared to meet the needs of our business today and tomorrow.

O&M declined 0.6% in 2019 even as we took the opportunity to invest more in key strategic and operational areas, including reducing operational risks and enhancing our customers' experience. While Xcel Energy continues to invest prudently in appropriate areas, we remain committed to our long-term objective of improving operating efficiencies and taking costs out of the business.

Deliver a Competitive Total Return to Investors and Maintain Strong Investment Grade Credit Rating

Successful execution of our strategic objectives should allow Xcel Energy to continue to deliver a competitive total return for our shareholders.

Through our disciplined approach to business growth, financial investment, operations and safety, we are well positioned to continue delivering on our value proposition.



We have consistently achieved our financial objectives, meeting or exceeding our initial earnings guidance range for fifteen consecutive years and delivering dividend growth for sixteen consecutive years.

Our ongoing earnings have grown 6.1% annually since 2005 and our dividend has grown 6.3% annually from 2013-2019. We work to maintain senior secured debt credit ratings in the A range and senior unsecured debt credit ratings in the BBB+ to A range. Our current ratings are consistent with this objective.

Environmental, Social and Governance Leadership

Xcel Energy has consistently demonstrated industry leadership in mitigating climate, operational and financial risks, while remaining committed to our customers, communities, employees and investors. We have delivered tangible environmental, social and governance results in alignment with our four corporate values - committed, connected, safe and trustworthy.

Environmental

Xcel Energy has been the number one U.S. wind provider for 12 of the past 14 years.

We continue to lead the industry with one of the most aggressive carbon reduction goals among our peers. Our plans to achieve 80% reduction by 2030 are aligned with Paris Accord goals and have been independently validated by an Intergovernmental Panel on Climate Change expert.

In December 2018, Xcel Energy became the first major electric utility in the country to announce an aspiration to produce 100% carbon-free electricity for customers by 2050.

Social

Xcel Energy works to mitigate the employee and community impacts of early plant retirements. We provide affected employees with advanced notice and offer retraining and relocation opportunities. Through these efforts and natural attrition, Xcel Energy has had no layoffs as a result of plant retirements.

We have also worked to foster economic sustainability and continued affordability through partnering with communities, policymakers and customers impacted by coal plant retirements, to build facilities and attract new businesses. Examples include:

- Near our Sherco plant, scheduled to close by 2030, we are partnering with local leadership and a major data center to locate a $600 million data center. Additionally, Xcel Energy actively worked to relocate a metal recycling plant near our plant; and
- We retained Evraz Steel in Colorado, a major Pueblo employer, by partnering with the company and community to create an affordable solar solution to meet their needs.

Xcel Energy is an active community member. We recognize and carefully evaluate the broader potential economic impacts of our decisions and work to proactively support the people and economic health of our communities. In 2019, we spent $3.1 billion locally, donated nearly $11 million to local charities, continued to offer employees 40 hours of volunteer paid time off annually and our employees served on over 500 non-profit boards. Donations include Xcel Energy employee and Xcel Energy Foundation gifts.

As a member of diverse communities, we value and celebrate diversity and inclusion. For example:

- Xcel Energy has offered domestic partner benefits since 1995;
- The Company's CEO has signed the Action for Diversity & Inclusion Pledge, for the advancement of diversity and inclusion within the workplace, and Xcel Energy has an employee-led Diversity & Inclusion Council;
- We have been selected among the nation's top corporations for lesbian, gay, bisexual, transgender, and queer equality by earning a perfect score on the Human Rights Campaign's 2019 Corporate Equality Index for the past 4 years; and
- Xcel Energy was named to the 2019 Military Times Best for Vets Employers rankings for the sixth straight year and currently employs more than 1,000 veterans, nearly 10% of our workforce.

Governance

Xcel Energy has a diverse and qualified Board of Directors committed to effective governance.

*Two new Board members effective March 1, 2020; six new Board members in the past five years

The Company first adopted an environmental policy and instituted Board of Directors' oversight of environmental performance in 2000, followed by publication of our corporate responsibility report in 2005.

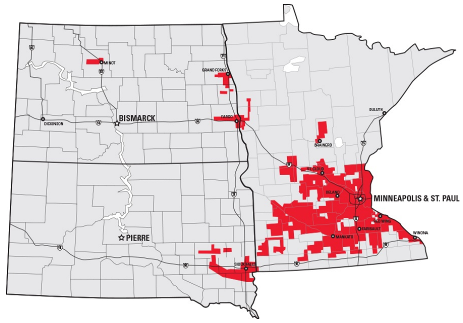
We consistently set aggressive goals and hold ourselves accountable, to our customers, our communities and our investors. Additionally, Xcel Energy was among the first U.S. utilities to tie carbon reduction directly to executive compensation over fifteen years ago and is one of three peer utilities who do so today.

We are also focused on safety for our employees and our communities. In 2019, 60% of annual incentive pay was tied to safety and system reliability. Employees at every level have "stop work authority" and are instrumental in keeping each other and our surrounding communities safe.

Utility Subsidiaries

NSP-Minnesota

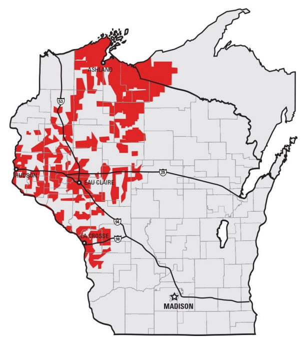
Electric customers	1.5 million
Natural gas customers	0.6 million
Consolidated earnings contribution	35% to 45%
Total assets	$19.9 billion
Rate Base	$11.2 billion
ROE	9.31%
Electric generating capacity	7,712 MW
Gas storage capacity	17.1 Bcf
Electric transmission lines (conductor miles)	33,528 miles
Electric distribution lines (conductor miles)	80,186 miles
Natural gas transmission lines	86 miles
Natural gas distribution lines	10,518 miles



NSP-Minnesota conducts business in Minnesota, North Dakota and South Dakota and has electric operations in all three states including the generation, purchase, transmission, distribution and sale of electricity. NSP-Minnesota and NSP-Wisconsin electric operations are managed on the NSP System. NSP-Minnesota also purchases, transports, distributes and sells natural gas to retail customers and transports customer-owned natural gas in Minnesota and North Dakota.

NSP-Wisconsin

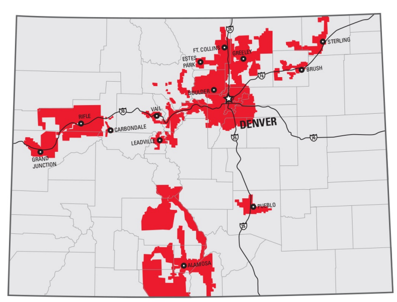
Electric customers	0.3 million
Natural gas customers	0.1 million
Consolidated earnings contribution	5% to 10%
Total assets	$2.8 billion
Rate Base	$1.7 billion
ROE	8.27%
Electric generating capacity	548 MW
Gas storage capacity	3.8 Bcf
Electric transmission lines (conductor miles)	12,285 miles
Electric distribution lines (conductor miles)	27,504 miles
Natural gas transmission lines	3 miles
Natural gas distribution lines	2,473 miles



NSP-Wisconsin conducts business in Wisconsin and Michigan and generates, transmits, distributes and sells electricity. NSP-Minnesota and NSP-Wisconsin electric operations are managed on the NSP System. NSP-Wisconsin also purchases, transports, distributes and sells natural gas to retail customers and transports customer-owned natural gas.

PSCo

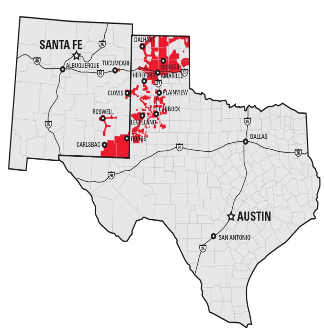
Electric customers	1.5 million
Natural gas customers	1.4 million
Consolidated earnings contribution	35% to 45%
Total assets	$19.0 billion
Rate Base	$12.4 billion
ROE	8.69%
Electric generating capacity	5,666 MW
Gas storage capacity	32.5 Bcf
Electric transmission lines (conductor miles)	24,008 miles
Electric distribution lines (conductor miles)	78,023 miles
Natural gas transmission lines	2,057miles
Natural gas distribution lines	22,633 miles



PSCo conducts business in Colorado and generates, purchases, transmits, distributes and sells electricity. PSCo also purchases, transports, distributes and sells natural gas to retail customers and transports customer-owned natural gas.

SPS

Electric customers	0.4 million
Consolidated earnings contribution	15% to 20%
Total assets	$7.9 billion
Rate base	$4.9 billion
ROE	9.71%
Electric generating capacity	4,804 MW
Electric transmission lines	38,418 miles
Electric distribution lines	21,810 miles



SPS conducts business in Texas and New Mexico and generates, purchases, transmits, distributes and sells electricity.

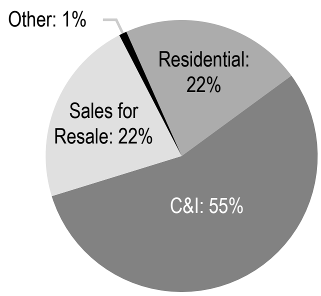
Operations Overview

Utility operations are generally conducted as either electric or gas utilities in our four utility subsidiaries.

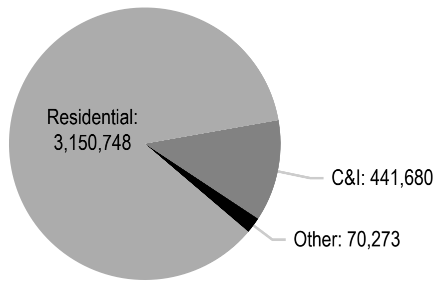
Electric Operations

Electric operations consist of energy supply, generation, transmission and distribution activities across all four operating companies. Xcel Energy had electric sales volume of 116,317 (millions of KWh), 3,662,701 customers and electric revenues of $9,575 (millions of dollars) for 2019.

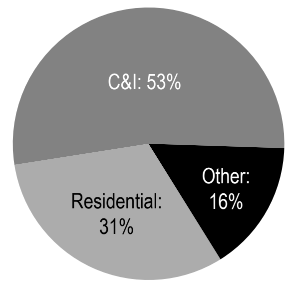
Sales Volume



Number of Customers



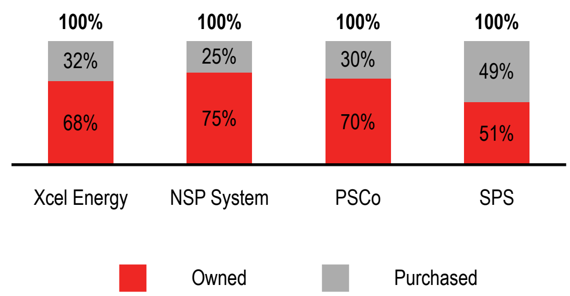
Revenues



Sales/Revenue Statistics

	2019	2018
KWh sales per retail customer	24,712	25,263
Revenue per retail customer	$2,244	$ 2,257
Residential revenue per KWh	11.97¢	11.78¢
Large C&I revenue per KWh	5.96¢	5.91¢
Small C&I revenue per KWh	9.43¢	9.21¢
Total retail revenue per KWh	9.08¢	8.93¢

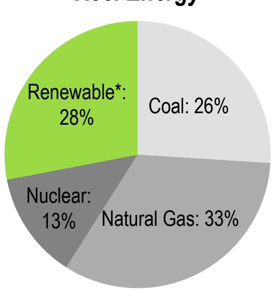
Owned and Purchased Energy Generation — 2019



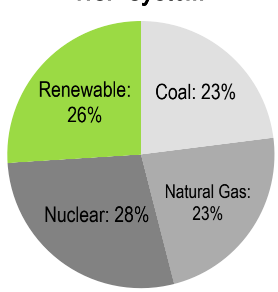
Electric Energy Sources

Total electric generation by source (including energy market purchases) for the year ended Dec. 31, 2019:

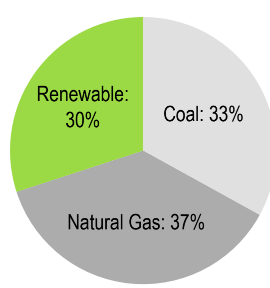
Xcel Energy



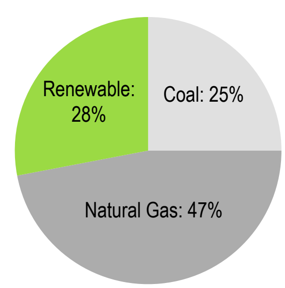
NSP System



PSCo



SPS



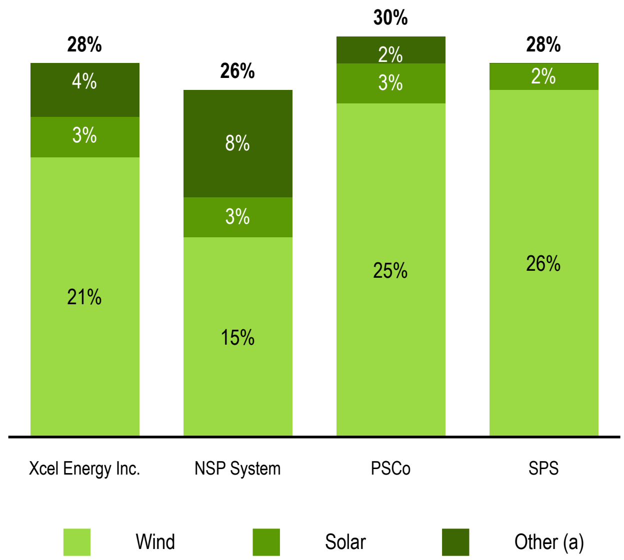
*Distributed generation from the Solar*Rewards® program is not included (approximately 538 million KWh for 2019)

Renewable Energy Sources

Xcel Energy's renewable energy portfolio includes wind, hydroelectric, biomass and solar power from both owned generating facilities and PPAs. Renewable percentages will vary year over year based on system additions, weather, system demand and transmission constraints.

See Item 2 — Properties for further information.

Renewable energy as a percentage of total energy for 2019:



(a) Includes biomass and hydroelectric

Wind Energy Sources

Owned — Owned and operated wind farms with corresponding capacity:

	2019		2018	
Utility Subsidiary	Wind Farms	Capacity	Wind Farms	Capacity
NSP System	7	1,090 MW	5	840 MW
PSCo	1	600 MW	1	600 MW
SPS	1	478 MW	—	—

PPAs — Number of PPAs with range:

	2019		2018	
Utility Subsidiary	PPAs	Range	PPAs	Range
NSP System	131	0.7 MW — 205.5 MW	132	0.7 MW - 205.5 MW
PSCo	20	2.0 MW — 300.5 MW	19	2.0 MW - 300.5 MW
SPS	18	0.7 MW — 250.0 MW	18	0.7 MW - 250.0 MW

Capacity — Wind capacity:

Utility Subsidiary	2019	2018
NSP System	2,780 MW	2,550 MW
PSCo	3,165 MW	3,160 MW
SPS	2,045 MW	1,565 MW

Average Cost (Owned) — Average cost per MWh of wind energy from owned generation:

Utility Subsidiary [(a)]	2019	2018
NSP System	$ 35	$ 37
PSCo	47	—

(a) The table reflects owned wind sites that were in commercial operation for the full calendar year. The Hale wind farm for SPS was put into service in June 2019 and the Rush Creek wind farm was put into service in December 2018.

Average Cost (PPAs) — Average cost per MWh of wind energy under existing PPAs:

Utility Subsidiary	2019	2018
NSP System	$ 41	$ 44
PSCo	41	43
SPS	25	26

Wind Energy Development

Xcel Energy is executing the largest multi-state wind investment in the nation and placed approximately 1,300 MW of owned wind and approximately 300 MW of PPAs into service during 2018-2019:

Project	Utility Subsidiary	Capacity
Rush Creek	PSCo	582 MW
Hale	SPS	460 MW
Foxtail	NSP-Minnesota	150 MW
Lake Benton	NSP-Minnesota	99 MW
Various PPAs	Various	~300 MW

As part of the multi-state wind investment, Xcel Energy currently has approximately 2,200 MW of owned wind under development or construction and approximately 900 MW of planned PPAs with an estimated completion date of 2021 or earlier:

Project	Utility Subsidiary	Capacity	Estimated Completion
Freeborn	NSP-Minnesota	200 MW	2020
Blazing Star 1	NSP-Minnesota	200 MW	2020
Blazing Star 2	NSP-Minnesota	200 MW	2020
Crowned Ridge [(a)]	NSP-Minnesota	200 MW	2020
Jeffers [(b)]	NSP-Minnesota	44 MW	2020
Community Wind North[(b)]	NSP-Minnesota	26 MW	2020
Dakota Range	NSP-Minnesota	300 MW	2021
Cheyenne Ridge	PSCo	500 MW	2020
Sagamore	SPS	522 MW	2020
Various PPAs	Various	~900 MW	2020 - 2021

(a) Build-own-transfer project.

(b) Repowering project.

Solar Energy Sources

Solar energy PPA(s):

Type	Utility Subsidiary	Capacity
Distributed Generation	NSP System	736 MW
Utility-Scale	NSP System	266 MW
Distributed Generation	PSCo	557 MW
Utility-Scale	PSCo	305 MW
Distributed Generation	SPS	10 MW
Utility-Scale	SPS	191 MW

Other Carbon-Free Energy Sources

Xcel Energy's other carbon-free energy portfolio includes nuclear from owned generating facilities.

See Item 2 — Properties for further information.

Nuclear Energy Sources

Xcel Energy has two nuclear plants with approximately 1,700 MW of total 2019 net summer dependable capacity that serves the NSP-System. Our nuclear fleet has become one of the safest and well-run in the nation, as rated by both the NRC and INPO.

The Company secures contracts for uranium concentrates, uranium conversion, uranium enrichment and fuel fabrication to operate its nuclear plants. The contract strategy involves a portfolio of spot purchases and medium and long-term contracts for uranium concentrates, conversion services and enrichment services with multiple producers and with a focus on diversification and alternate sources to minimize potential impacts caused by supply interruptions due to geographical and world political issues.

Nuclear Fuel Cost

Delivered cost per MMBtu of nuclear fuel consumed for owned electric generation and the percentage of total fuel requirements:

Utility Subsidiary	Nuclear	
NSP System	Cost	Percent
2019	$ 0.81	45%
2018	0.80	45

Fossil Fuel Energy Sources

Xcel Energy's fossil fuel energy portfolio includes coal and natural gas power from both owned generating facilities and PPAs.

See Item 2 — Properties for further information.

Coal Energy Sources

Xcel Energy owns and operates nine coal plants with approximately 6,500 MW of total 2019 net summer dependable capacity.

Our operating companies have embarked on an industry-leading coal retirement program with permission from its key regulatory bodies.

Approved and proposed coal plant retirements:

Approved (2019 to 2027)

Year	Utility Subsidiary	Plant	Capacity
2022	PSCo	Comanche 1	325 MW
2023	NSP-Minnesota	Sherco 2	682 MW
2025	PSCo	Comanche 2	335 MW
2025	PSCo	Craig 1	42 MW
2026	NSP-Minnesota	Sherco 1	680 MW

Proposed (2028 to 2030)

Year	Utility Subsidiary	Plant	Capacity
2028	NSP-Minnesota	A.S King	511 MW
2030	NSP-Minnesota	Sherco 3	517 MW

Coal Fuel Cost

Delivered cost per MMBtu of coal consumed for owned electric generation and percentage of fuel requirements:

Utility Subsidiary	Coal [(a)] Cost	Coal [(a)] Percent
NSP System		
2019	$ 2.02	36%
2018	2.13	42
PSCo		
2019	1.45	55
2018	1.45	62
SPS		
2019	2.19	45
2018	2.04	56

(a) Includes refuse-derived fuel and wood for the NSP System.

Natural Gas Energy Sources

Xcel Energy has 22 natural gas plants with approximately 7,900 MW of total 2019 net summer dependable capacity.

Natural gas supplies, transportation and storage services for power plants are procured to provide an adequate supply of fuel. Remaining requirements are procured through a liquid spot market. Generally, natural gas supply contracts have variable pricing that is tied to natural gas indices. Natural gas supply and transportation agreements include obligations for the purchase and/or delivery of specified volumes or payments in lieu of delivery.

Natural Gas Cost

Delivered cost per MMBtu of natural gas consumed for owned electric generation and percentage of total fuel requirements:

Utility Subsidiary	Natural Gas Cost	Natural Gas Percent
NSP System		
2019	$ 3.09	19%
2018	3.87	13
PSCo		
2019	3.27	45
2018	3.74	38
SPS		
2019	1.14	55
2018	2.24	44

Capacity and Demand

Uninterrupted system peak demand and occurrence date for the regulated utilities:

Utility Subsidiary	System Peak Demand (in MW) 2019		2018	
NSP System	8,774	July 19	8,927	June 29
PSCo	7,111	July 19	6,718	July 10
SPS	4,261	Aug. 5	4,648	July 19

Transmission

Transmission lines deliver electricity over long distances from power sources to transmission substations closer to homes and businesses. A strong transmission system ensures continued reliable and affordable service, ability to meet state and regional energy policy goals, and support a diverse generation mix, including renewable energy. Xcel Energy owns more than 20,000 miles of transmission lines, serving 22,000 MW of customer load.

Transmission projects completed in 2019 include:

Project	Utility Subsidiary	Miles	Size
Maple River-Red River	NSP-Minnesota	5	115 KV
Nelson-Wabasha	NSP-Wisconsin	2	69 KV
Pawnee-Daniels Park	PSCo	125	345 KV
Thornton Substation	PSCo	2	115 KV
TUCO-Yoakum-Hobbs	SPS	64	345 KV
NEF-Cardinal	SPS	15	115 KV
Potash Junction-Livingston Ridge	SPS	15	115 KV
Mustang-Shell	SPS	9	115 KV
North Loving-South Loving	SPS	3	115 KV
Cunningham-Monument Tap	SPS	7	115 KV

Notable upcoming projects:

Project	Utility Subsidiary	Miles	Size	Completion Date
Huntley-Wilmarth	NSP-Minnesota	50	345 KV	2021
Bayfield Second Circuit	NSP-Wisconsin	19	35 KV	2022
Cheyenne Ridge	PSCo	65	345 KV	2020
TUCO-Yoakum-Hobbs	SPS	106	345 KV	2020
Eddy-Kiowa	SPS	34	345 KV	2020

See Item 2 - Properties for further information.

Distribution

Distribution lines allow electricity to travel from substations directly to homes and businesses in neighborhoods and cities around the country. Xcel Energy has a vast distribution network, owning and operating thousands of miles of distribution lines across our eight-state service territory, both above ground and underground.

To continue providing reliable, affordable electric service and enable more flexibility for customers, we are working to digitize the distribution grid, while at the same time keeping it secure. Over the next five years, the Company will invest $1.4 billion implementing new network infrastructure, smart meters, advanced software, equipment sensors and related data analytics capabilities. These investments will further improve reliability and reduce outage restoration times for our customers, while at the same time enabling new options and opportunities for increased efficiency savings. The new capabilities will also enable integration of battery storage and other distributed energy resources into the grid, including electric vehicles.

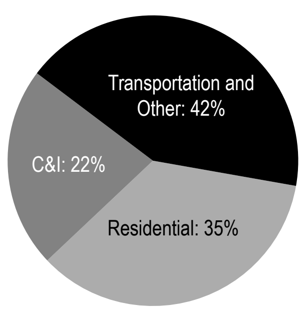
In 2019, Xcel Energy implemented foundational software and completed our initial smart meter deployment in Colorado as planned, with full-scale implementation to follow. We also requested approval to expand our advanced grid program to benefit our Minnesota customers and expect a Commission decision in late 2020. We plan to have smart meters implemented across our Colorado and Minnesota service territories by the end of 2024.

See Item 2 - Properties for further information.

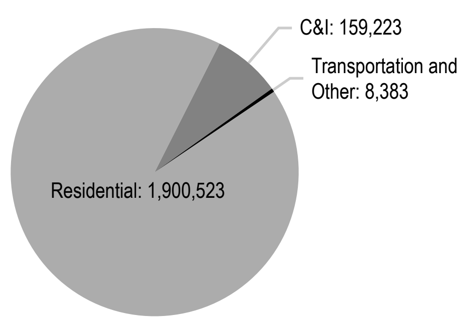
Natural Gas Operations

Natural gas operations consist of purchase, transportation and distribution of natural gas to end use residential, C&I and transport customers in NSP-Minnesota, NSP-Wisconsin and PSCo. Xcel Energy had natural gas deliveries of 463,185 (thousands of MMBtu), 2,068,129 customers and natural gas revenues of $1,868 (millions of dollars) for 2019.

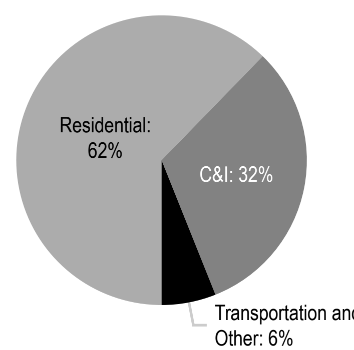
Deliveries



Number of Customers



Revenues



Sales/Revenue Statistics

	2019	2018
MMBtu sales per retail customer	129.31	120.51
Revenue per retail customer	$ 851.94	$ 785.86
Residential revenue per MMBtu	7.14	7.01
C&I revenue per MMBtu	5.73	5.76
Transportation and other revenue per MMBtu	0.57	0.80

Capability and Demand

Natural gas supply requirements are categorized as firm or interruptible (customers with an alternate energy supply).

Maximum daily output (firm and interruptible) and occurrence date:

	2019		2018	
Utility Subsidiary	MMBtu	Date	MMBtu	Date
NSP-Minnesota	897,615 [(a)]	Feb. 25	786,751	Jan. 12
NSP-Wisconsin	166,009 [(a)]	Jan. 30	159,700	Jan. 5
PSCo	2,139,420 [(a)]	March 3	1,903,878	Feb. 20

(a) Increase in maximum MMBtu output due to colder winter temperatures in 2019.

Natural Gas Supply and Cost

Xcel Energy actively seeks natural gas supply, transportation and storage alternatives to yield a diversified portfolio, which provides increased flexibility, decreased interruption and financial risk, and economic customer rates. In addition, the utility subsidiaries conduct natural gas price hedging activities approved by their state commissions.

Average delivered cost per MMBtu of natural gas for regulated retail distribution:

Utility Subsidiary	2019	2018
NSP-Minnesota	$ 3.71	$ 4.03
NSP-Wisconsin	3.49	3.84
PSCo	2.95	3.20

NSP-Minnesota, NSP-Wisconsin and PSCo have natural gas supply transportation and storage agreements that include obligations for purchase and/or delivery of specified volumes or to make payments in lieu of delivery.

See Item 2 - Properties for further information.

General

General Economic Conditions

Economic conditions may have a material impact on Xcel Energy’s operating results. Other events impact overall economic conditions and management cannot predict the impact of fluctuating energy prices, terrorist activity, war or the threat of war. We could experience a material impact to its results of operations, future growth or ability to raise capital resulting from a sustained general slowdown in economic growth or a significant increase in interest rates.

Seasonality

Demand for electric power and natural gas is affected by seasonal differences in the weather. In general, peak sales of electricity occur in the summer months and peak sales of natural gas occur in the winter months. As a result, the overall operating results may fluctuate substantially on a seasonal basis. Additionally, Xcel Energy’s operations have historically generated less revenues and income when weather conditions are milder in the winter and cooler in the summer.

Competition

The Company is subject to public policies that promote competition and development of energy markets. Xcel Energy’s industrial and large commercial customers have the ability to generate their own electricity. In addition, customers may have the option of substituting other fuels or relocating their facilities to a lower cost region.

Customers have the opportunity to supply their own power with distributed generation including solar generation and in most jurisdictions can currently avoid paying for most of the fixed production, transmission and distribution costs incurred to serve them.

Several states have incentives for the development of rooftop solar, community solar gardens and other distributed energy resources. Distributed generating resources are potential competitors to Xcel Energy’s electric service business with these incentives and federal tax subsidies.

The FERC has continued to promote competitive wholesale markets through open access transmission and other means. Xcel Energy’s wholesale customers can purchase their output from generation resources of competing suppliers or non-contracted quantities and use the transmission systems of the utility subsidiaries on a comparable basis to serve their native load.

FERC Order No. 1000 established competition for construction and operation of certain new electric transmission facilities. State utilities commissions have also created resource planning programs that promote competition for electricity generation resources used to provide service to retail customers.

Xcel Energy Inc.’s utility subsidiaries have franchise agreements with cities subject to periodic renewal; however, a city could seek alternative means to access electric power or gas, such as municipalization.

While each utility subsidiary faces these challenges, Xcel Energy believes their rates and services are competitive with alternatives currently available.

Public Utility Regulation

See Item 7 for discussion of public utility regulation.

Environmental

Environmental Regulation

Our facilities are regulated by federal and state agencies that have jurisdiction over air emissions, water quality, wastewater discharges, solid wastes and hazardous substances. Various company activities require registrations, permits, licenses, inspections and approvals from these agencies. Xcel Energy has received necessary authorizations for the construction and continued operation of its generation, transmission and distribution systems. Our facilities have been designed and constructed to operate in compliance with applicable environmental standards and related monitoring and reporting requirements. However, it is not possible to determine when or to what extent additional facilities or modifications of existing or planned facilities will be required as a result of changes to regulations, interpretations or enforcement policies or what effect future laws or regulations may have. We may be required to incur expenditures in the future for remediation of MGP and other sites if it is determined that prior compliance efforts are not sufficient.

In Minnesota, Texas and Wisconsin, Xcel Energy must comply with emission budgets that require the purchase of emission allowances from other utilities. The Denver North Front Range Nonattainment Area does not meet either the 2008 or 2015 ozone NAAQS. Colorado will continue to consider further reductions available in the non-attainment area as it develops plans to meet ozone standards. Gas plants which operate in PSCo’s non-attainment area may be required to improve or add controls, implement further work practices and/or enhanced emissions monitoring as part of future Colorado state plans.

There are significant present/future environmental regulations to encourage use of clean energy technologies and regulate emissions of GHGs. We have undertaken numerous initiatives to meet current requirements and prepare for potential future regulations, reduce GHG emissions and respond to state renewable and energy efficiency goals. If future environmental regulations do not take into consideration investments already made or if additional initiatives or emission reductions are required, substantial costs may be incurred.

In July 2019, the EPA adopted the Affordable Clean Energy rule, which requires states to develop plans for GHG reductions from coal-fired power plants. The state plans, due to the EPA in July 2022, will evaluate and potentially require heat rate improvements at existing coal-fired plants. It is not yet known how these state plans will affect our existing coal plants, but they could require substantial additional investment, even in plants slated for retirement. Xcel Energy believes, based on prior state commission practice, the cost of these initiatives or replacement generation would be recoverable through rates.

In 2019, Xcel Energy estimates that it reduced the carbon emissions associated with the electric generating resources, both owned and under PPAs, used to serve its customers by approximately 44% from 2005 levels.

Environmental Costs

Environmental costs include accruals for nuclear plant decommissioning and payments for storage of spent nuclear fuel, disposal of hazardous materials and waste, remediation of contaminated sites, monitoring of discharges to the environment and compliance with laws and permits with respect to emissions.

Costs charged to operating expenses for nuclear decommissioning, spent nuclear fuel disposal, environmental monitoring and remediation and disposal of hazardous materials and waste were approximately:

- $345 million in 2019;
- $335 million in 2018; and
- $315 million in 2017.

Average annual expense of approximately $400 million from 2020 – 2024 is estimated for similar costs. The precise timing and amount of environmental costs, including those for site remediation and disposal of hazardous materials, are unknown. Additionally, the extent to which environmental costs will be included in and recovered through rates may fluctuate.

Capital expenditures for environmental improvements were approximately:

- $30 million in 2019;
- $50 million in 2018; and
- $60 million in 2017.

See Item 7 — Capital Requirements for further discussion.

Capital Spending and Financing

See Item 7 for discussion of capital expenditures and funding sources.

Employees

As of Dec. 31, 2019, Xcel Energy had 11,273 full-time employees and 44 part-time employees, of which 5,091 were covered under CBAs.

	Employees Covered by CBAs	Total Employees
NSP-Minnesota	2,036	3,203
NSP-Wisconsin	392	538
PSCo	1,884	2,369
SPS	779	1,158
XES	—	4,005
Total	5,091	11,273

Information about our Executive Officers [(a)]

Name	Age [(b)]	Current and Recent Positions	Time in Position
Ben Fowke [(c)]	61	Chairman of the Board, President and Chief Executive Officer and Director, Xcel Energy Inc.	August 2011 — Present
		Chief Executive Officer, NSP-Minnesota, NSP-Wisconsin, PSCo, and SPS	January 2015 — Present
Brett C. Carter	53	Executive Vice President and Chief Customer and Innovation Officer, Xcel Energy Inc.	May 2018 — Present
		Senior Vice President and Shared Services Executive, Bank of America, an institutional investment bank and financial services company	October 2015 — May 2018
		Senior Vice President and Chief Operating Officer, Bank of America	March 2015 — October 2015
		Senior Vice President and Chief Distribution Officer, Duke Energy Co., an electric power company	February 2013 — March 2015
Christopher B. Clark	53	President and Director, NSP-Minnesota	January 2015 — Present
David L. Eves [(d)]	61	Executive Vice President and Group President, Utilities, Xcel Energy Inc.	March 2018 — Present
		President and Director, PSCo	January 2015 — February 2018
Darla Figoli	57	Senior Vice President, Human Resources & Employee Services, Chief Human Resources Officer, Xcel Energy Inc.	May 2018 — Present
		Senior Vice President, Human Resources and Employee Services, Xcel Energy Inc.	May 2015 — May 2018
		Vice President, Human Resources, Xcel Energy Inc.	February 2010 — May 2015
Robert C. Frenzel [(c)]	49	Executive Vice President, Chief Financial Officer, Xcel Energy Inc.	May 2016 — Present
		Senior Vice President and Chief Financial Officer, Luminant, a subsidiary of Energy Future Holdings Corp. [(e)]	February 2012 — April 2016
David T. Hudson	59	President and Director, SPS	January 2015 — Present
Alice Jackson	41	President and Director, PSCo	May 2018 — Present
		Area Vice President, Strategic Revenue Initiatives, Xcel Energy Services Inc.	November 2016 — May 2018
		Regional Vice President, Rates and Regulatory Affairs, PSCo	November 2013 — November 2016
Kent T. Larson [(f)]	60	Executive Vice President and Group President Operations, Xcel Energy Inc.	January 2015 — Present
Timothy O'Connor [(g)]	60	Senior Vice President, Chief Nuclear Officer, Xcel Energy Services Inc.	February 2013 — Present
Judy M. Poferl [(h)]	60	Senior Vice President, Corporate Secretary and Executive Services, Xcel Energy Inc.	January 2015 — Present
Jeffrey S. Savage	48	Senior Vice President, Controller, Xcel Energy Inc.	January 2015 — Present
Mark E. Stoering	59	President and Director, NSP-Wisconsin	January 2015 — Present
Scott M. Wilensky	63	Executive Vice President, General Counsel, Xcel Energy Inc.	January 2015 — Present

(a) No family relationships exist between any of the executive officers or directors.

(b) Ages as of Dec. 31, 2019.

(c) Effective March 31, 2020, Mr. Fowke will cease to serve as President and Mr. Frenzel will become President and Chief Operating Officer of Xcel Energy Inc. At the same time, Brian J. Van Abel will become Executive Vice President, Chief Financial Officer of Xcel Energy Inc.

(d) Effective May 1, 2020, Mr. Eves will be retiring from the Company after retiring from his executive officer positions effective March 30, 2020.

(e) In April 2014, Energy Future Holdings Corp., the majority of its subsidiaries, including TCEH the parent company of Luminant, filed a voluntary bankruptcy petition under Chapter 11 of the United States Bankruptcy Code. TCEH emerged from Chapter 11 in October 2016.

(f) Effective May 31, 2020, Mr. Larson will be leaving the Company after ceasing to serve in his executive officer positions effective March 30, 2020.

(g) Effective March 31, 2020, Mr. O'Connor will become Executive Vice President, Chief Generation Officer.

(h) Effective March 31, 2020, Ms. Poferl will be retiring from the Company. Frank Prager has been elected to serve with the title of Senior Vice President, Strategy and Planning and External Affairs effective March 1, 2020.

ITEM 1A — RISK FACTORS

Xcel Energy is subject to a variety of risks, many of which are beyond our control. Risks that may adversely affect the business, financial condition, results of operations or cash flows are described below. These risks should be carefully considered together with the other information set forth in this report and future reports that we file with the SEC.

Oversight of Risk and Related Processes

The Board of Directors is responsible for the oversight of material risk and maintaining an effective risk monitoring process. Management and the Board of Directors' committees have responsibility for overseeing the identification and mitigation of key risks and reporting its assessments and activities to the full Board of Directors.

Xcel Energy maintains a robust compliance program and promotes a culture of compliance beginning with the tone at the top. The risk mitigation process includes adherence to our code of conduct and compliance policies, operation of formal risk management structures and overall business management. Xcel Energy further mitigates inherent risks through formal risk committees and corporate functions such as internal audit, and internal controls over financial reporting and legal.

Management identifies and analyzes risks to determine materiality and other attributes such as timing, probability and controllability. Identification and risk analysis occurs formally through risk assessment conducted by senior management, the financial disclosure process, hazard risk procedures, internal audit and compliance with financial and operational controls.

Management also identifies and analyzes risk through the business planning process, development of goals and establishment of key performance indicators, including identification of barriers to implementing the Company's strategy. The business planning process also identifies likelihood and mitigating factors to prevent the assumption of inappropriate risk to meet goals.

Management communicates regularly with the Board of Directors and key stakeholders regarding risk. Senior management presents and communicates a periodic risk assessment to the Board of Directors, providing information on the risks that management believes are material, including financial impact, timing, likelihood and mitigating factors. The Board of Directors regularly reviews management's key risk assessments, which includes areas of existing and future macroeconomic, financial, operational, policy, environmental and security risks.

The oversight, management and mitigation of risk is an integral and continuous part of the Board of Directors' governance of Xcel Energy. The Board of Directors assigns oversight of critical risks to each of its four committees to ensure these risks are well understood and given appropriate focus.

The Audit Committee is responsible for reviewing the adequacy of the committee's risk oversight and affirming appropriate aggregate oversight occurs. Committees regularly report on their oversight activities and certain risk issues may be brought to the full Board of Directors for consideration when deemed appropriate.

New risks are considered and assigned as appropriate during the annual Board of Directors and committee evaluation process, resulting in updates to the committee charters and annual work plans. Additionally, the Board of Directors conducts an annual strategy session where Xcel Energy's future plans and initiatives are reviewed.

Risks Associated with Our Business

Operational Risks

Our natural gas and electric transmission and distribution operations involve numerous risks that may result in accidents and other operating risks and costs.

Our natural gas transmission and distribution activities include inherent hazards and operating risks, such as leaks, explosions, outages and mechanical problems. Our electric generation, transmission and distribution activities include inherent hazards and operating risks such as contact, fire and outages. These risks could result in loss of life, significant property damage, environmental pollution, impairment of our operations and substantial financial losses. We maintain insurance against most, but not all, of these risks and losses. The occurrence of these events, if not fully covered by insurance, could have a material effect on our financial condition, results of operations and cash flows.

Additionally, compliance with existing and potential new regulations related to the operation and maintenance of our natural gas infrastructure could result in significant costs. The PHMSA is responsible for administering the DOT's national regulatory program to assure the safe transportation of natural gas, petroleum and other hazardous materials by pipelines. The PHMSA continues to develop regulations and other approaches to risk management to assure safety in design, construction, testing, operation, maintenance and emergency response of natural gas pipeline infrastructure. We have programs in place to comply with these regulations and systematically monitor and renew infrastructure over time, however, a significant incident or material finding of non-compliance could result in penalties and higher costs of operations.

Our natural gas and electric transmission and distribution operations are dependent upon complex information technology systems and network infrastructure, the failure of which could disrupt our normal business operations, which could have a material adverse effect on our ability to process transactions and provide services.

Our utility operations are subject to long-term planning and project risks.

Most electric utility investments are planned to be used for decades. Transmission and generation investments typically have long lead times and are planned well in advance of in-service dates and typically subject to long-term resource plans. These plans are based on numerous assumptions such as: sales growth, customer usage, commodity prices, economic activity, costs, regulatory mechanisms, customer behavior, available technology and public policy. Xcel Energy's long-term resource plan is dependent on our ability to obtain required approvals, develop necessary technical expertise, allocate and coordinate sufficient resources and adhere to budgets and timelines.

In addition, the long-term nature of both our planning and our asset lives are subject to risk. The electric utility sector is undergoing a period of significant change. For example, increases in energy efficiency, wider adoption of lower cost renewable generation, distributed generation and shifts away from coal generation to decrease carbon emissions and increasing use of natural gas in electric generation driven by lower natural gas prices. Customer adoption of these technologies and increased energy efficiency could result in excess transmission and generation resources, downward pressure on sales growth, as well as stranded costs if we are not able to fully recover costs and investments.

Changing customer expectations and technologies are requiring significant investments in advanced grid infrastructure, which increases exposure to technology obsolescence. Evolving stakeholder preference for lower emission generation sources may pressure our investments in natural gas generation and delivery.

The magnitude and timing of resource additions and changes in customer demand may not coincide while customer preference for resource generation may change, which introduces further uncertainty into long-term planning. Additionally, multiple states may not agree as to the appropriate resource mix, which may lead to costs to comply with one jurisdiction that are not recoverable across all jurisdictions served by the same assets.

We are subject to longer-term availability of inputs such as coal, natural gas, uranium and water to cool our facilities. Lack of availability of these resources could jeopardize long-term operations of our facilities or make them uneconomic to operate.

We are subject to commodity risks and other risks associated with energy markets and energy production.

In the event fuel costs increase, customer demand could decline and bad debt expense may rise, which may have a material impact on our results of operations. Despite existing fuel recovery mechanisms in most of our states, higher fuel costs could significantly impact our results of operations if costs are not recovered. Delays in the timing of the collection of fuel cost recoveries could impact our cash flows.

A significant disruption in supply could cause us to seek alternative supply services at potentially higher costs and supply shortages may not be fully resolved, which could cause disruptions in our ability to provide services to our customers. Failure to provide service due to disruptions may also result in fines, penalties or cost disallowances through the regulatory process. Also, significantly higher energy or fuel costs relative to sales commitments could negatively impact our cash flows and results of operations.

We also engage in wholesale sales and purchases of electric capacity, energy and energy-related products as well as natural gas. In many markets, emission allowances and/or RECs are also needed to comply with various statutes and commission rulings. As a result, we are subject to market supply and commodity price risk. Commodity price changes can affect the value of our commodity trading derivatives. We mark certain derivatives to estimated fair market value on a daily basis. Settlements can vary significantly from estimated fair values recorded and significant changes from the assumptions underlying our fair value estimates could cause earnings variability.

Failure to attract and retain a qualified workforce could have an adverse effect on operations.

Certain specialized knowledge is required of our technical employees for construction and operation of transmission, generation and distribution assets. The Company's business strategy is dependent on our ability to recruit, retain and motivate employees. Competition for skilled employees is high in the areas of business operations. Failure to hire and adequately train replacement employees, including the transfer of significant internal historical knowledge and expertise to new employees or future availability and cost of contract labor may adversely affect the ability to manage and operate our business. We have seen a tightening of supply for engineers and skilled laborers in certain markets and are implementing plans to retain these employees. Inability to attract and retain these employees could adversely impact our results of operations, financial condition or cash flows.

Our operations use third-party contractors in addition to employees to perform periodic and ongoing work.

We rely on third-party contractors to perform operations, maintenance and construction work. Our contractual arrangements with these contractors typically include performance standards, progress payments, insurance requirements and security for performance. Poor vendor performance could impact ongoing operations, restoration operations, our reputation and could introduce financial risk or risks of fines.

Our subsidiary, NSP-Minnesota, is subject to the risks of nuclear generation.

NSP-Minnesota has two nuclear generation plants, PI and Monticello. Risks of nuclear generation include:

- Hazards associated with the use of radioactive material in energy production, including management, handling, storage and disposal;
- Limitations on insurance available to cover losses that may arise in connection with nuclear operations, as well as obligations to contribute to an insurance pool in the event of damages at a covered U.S. reactor; and
- Technological and financial uncertainties related to the costs of decommissioning nuclear plants may cause our funding obligations to change.

The NRC has authority to impose licensing and safety-related requirements for the operation of nuclear generation facilities, including the ability to impose fines and/or shut down a unit until compliance is achieved. Revised NRC safety requirements could necessitate substantial capital expenditures or an increase in operating expenses. In addition, the Institute for Nuclear Power Operations reviews NSP-Minnesota's nuclear operations and nuclear generation facilities. Compliance with the Institute for Nuclear Power Operations' recommendations could result in substantial capital expenditures or a substantial increase in operating expenses.

If an incident did occur, it could have a material impact on our results of operations, financial condition or cash flows. Furthermore, non-compliance or the occurrence of a serious incident at other nuclear facilities could result in increased industry regulation, which may increase NSP-Minnesota's compliance costs.

NSP-Wisconsin's production and transmission system is operated on an integrated basis with NSP-Minnesota and may be subject to risks associated with NSP-Minnesota's nuclear generation.

Financial Risks

Our profitability depends on the ability of our utility subsidiaries to recover their costs and changes in regulation may impair the ability of our utility subsidiaries to recover costs from their customers.

We are subject to comprehensive regulation by federal and state utility regulatory agencies, including siting and construction of facilities, customer service and the rates that we can charge customers.

The profitability of our utility operations is dependent on our ability to recover the costs of providing energy and utility services and earning a return on capital investment. Our rates are generally regulated and are based on an analysis of the utility's costs incurred in a test year. The utility subsidiaries are subject to both future and historical test years depending upon the regulatory jurisdiction. Thus, the rates a utility is allowed to charge may or may not match its costs at any given time. Rate regulation is premised on providing an opportunity to earn a reasonable rate of return on invested capital.

There can also be no assurance that our regulatory commissions will judge all the costs of our utility subsidiaries to be prudent, which could result in disallowances, or that the regulatory process will always result in rates that will produce full recovery.

Overall, management believes prudently incurred costs are recoverable given the existing regulatory framework. However, there may be changes in the regulatory environment that could impair the ability of our utility subsidiaries to recover costs historically collected from customers, or these subsidiaries could exceed caps on capital costs (e.g., wind projects) required by commissions and result in less than full recovery.

Changes in the long-term cost-effectiveness or to the operating conditions of our assets may result in early retirements of utility facilities. While regulation typically provides relief for these types of changes, there is no assurance that regulators would allow full recovery of all remaining costs.

In a continued low interest rate environment, there has been increased downward pressure on allowed ROE. Conversely, higher than expected inflation or tariffs may increase costs of construction and operations. Also, rising fuel costs could increase the risk that our utility subsidiaries will not be able to fully recover their fuel costs from their customers.

Adverse regulatory rulings or the imposition of additional regulations could have an adverse impact on our results of operations and materially affect our ability to meet our financial obligations, including debt payments and the payment of dividends on common stock.

Any reductions in our credit ratings could increase our financing costs and the cost of maintaining certain contractual relationships.

We cannot be assured that our current ratings or our subsidiaries' ratings will remain in effect, or that a rating will not be lowered or withdrawn by a rating agency. Significant events including disallowance of costs, significantly lower returns on equity, changes to equity ratios and impacts of tax policy may impact our cash flows and credit metrics, potentially resulting in a change in our credit ratings. In addition, our credit ratings may change as a result of the differing methodologies or change in the methodologies used by the various rating agencies.

Any downgrade could lead to higher borrowing costs and could impact our ability to access capital markets. Also, our utility subsidiaries may enter into contracts that require posting of collateral or settlement of applicable contracts if credit ratings fall below investment grade.

We are subject to capital market and interest rate risks.

Utility operations require significant capital investment. As a result, we frequently need to access capital markets. Capital markets are global and impacted by issues and events throughout the world. Any disruption in capital markets could have a material impact on our ability to fund our operations. Capital market disruption and financial market distress could prevent us from issuing short-term commercial paper, issuing new securities or cause us to issue securities with unfavorable terms and conditions, such as higher interest rates. Higher interest rates on short-term borrowings with variable interest rates could also have an adverse effect on our operating results.

The performance of capital markets impacts the value of assets held in trusts to satisfy future obligations to decommission NSP-Minnesota's nuclear plants and satisfy our defined benefit pension and postretirement benefit plan obligations. These assets are subject to market fluctuations and yield uncertain returns, which may fall below expected returns. A decline in the market value of these assets may increase funding requirements. Additionally, the fair value of the debt securities held in the nuclear decommissioning and/or pension trusts may be impacted by changes in interest rates.

We are subject to credit risks.

Credit risk includes the risk that our customers will not pay their bills, which may lead to a reduction in liquidity and an increase in bad debt expense. Credit risk is comprised of numerous factors including the price of products and services provided, the overall economy and local economies in the geographic areas we serve, including local unemployment rates. Credit risk also includes the risk that various counterparties that owe us money or product will become insolvent and may breach their obligations. Should the counterparties fail to perform, we may be forced to enter into alternative arrangements. In that event, our financial results could be adversely affected and incur losses.

The Company may at times have direct credit exposure in our short-term wholesale and commodity trading activity to financial institutions trading for their own accounts or issuing collateral support on behalf of other counterparties. We may also have some indirect credit exposure due to participation in organized markets, such as CAISO, SPP, PJM Interconnection, LLC, MISO and Electric Reliability Council of Texas, in which any credit losses are socialized to all market participants. We have additional indirect credit exposure to financial institutions in the form of letters of credit provided as security by power suppliers under various purchased power contracts. If any of the credit ratings of the letter of credit issuers were to drop below investment grade, the supplier would need to replace that security with an acceptable substitute. If the security were not replaced, the party could be in default under the contract.

Increasing costs of our defined benefit retirement plans and employee benefits may adversely affect our results of operations, financial condition or cash flows.

We have defined benefit pension and postretirement plans that cover most of our employees. Assumptions related to future costs, return on investments, interest rates and other actuarial assumptions have a significant impact on our funding requirements related to these plans. Estimates and assumptions may change. In addition, the Pension Protection Act changed the minimum funding requirements for defined benefit pension plans. Therefore, our funding requirements and related contributions may change in the future. Also, the payout of a significant percentage of pension plan liabilities in a single year due to high numbers of retirements or employees leaving would trigger settlement accounting and could require Xcel Energy to recognize incremental pension expense related to unrecognized plan losses in the year liabilities are paid.

Changes in industry standards utilized in key assumptions (e.g., mortality tables) could have a significant impact on future obligations and benefit costs.

Increasing costs associated with health care plans may adversely affect our results of operations.

Increasing levels of large individual health care claims and overall health care claims could have an adverse impact on our results of operations, financial condition or cash flows. Health care legislation could also significantly impact our benefit programs and costs.

We must rely on cash from our subsidiaries to make dividend payments.

Investments in our subsidiaries are our primary assets. Substantially all of our operations are conducted by our subsidiaries. Consequently, our operating cash flow and ability to service our debt and pay dividends depends upon the operating cash flows of our subsidiaries and their payment of dividends.

Our subsidiaries are separate legal entities that have no obligation to pay any amounts due pursuant to our obligations or to make any funds available for dividends on our common stock. In addition, each subsidiary's ability to pay dividends depends on statutory and/or contractual restrictions which may include requirements to maintain minimum levels of equity ratios, working capital or assets.

If the utility subsidiaries were to cease making dividend payments, our ability to pay dividends on our common stock or otherwise meet our financial obligations could be adversely affected. Our utility subsidiaries are regulated by state utility commissions, which possess broad powers to ensure that the needs of the utility customers are met. We may be negatively impacted by the actions of state commissions that limit the payment of dividends by our subsidiaries.

Federal tax law may significantly impact our business.

Our utility subsidiaries collect through regulated rates estimated federal, state and local tax payments. Changes to federal tax law may benefit or adversely affect our earnings and customer costs. Tax depreciable lives and the value of various tax credits or the timeliness of their utilization may impact the economics or selection of resources. There could be timing delays before regulated rates provide for realization of tax changes in revenues. In addition, certain IRS tax policies, such as tax normalization, may impact our ability to economically deliver certain types of resources relative to market prices.

Macroeconomic Risks

Economic conditions impact our business.

Xcel Energy's operations are affected by local, national and worldwide economic conditions, which correlates to customers/sales growth(decline). Economic conditions may be impacted by insufficient financial sector liquidity leading to potential increased unemployment, which may impact customers' ability to pay their bills which could lead to additional bad debt expense.

Our utility subsidiaries face competitive factors, which could have an adverse impact on our financial condition, results of operations and cash flows. Further, worldwide economic activity impacts the demand for basic commodities necessary for utility infrastructure, which may inhibit our ability to acquire sufficient supplies. We operate in a capital intensive industry and federal trade policy could significantly impact the cost of materials we use. There may be delays before these additional material costs can be recovered in rates.

Operations could be impacted by war, terrorism, or other events.

Our generation plants, fuel storage facilities, transmission and distribution facilities and information and control systems may be targets of terrorist activities. Any disruption could impact operations or result in a decrease in revenues and additional costs to repair and insure our assets. These disruptions could have a material impact on our financial condition, results of operations or cash flows. The potential for terrorism has subjected our operations to increased risks and could have a material effect on our business. We have already incurred increased costs for security and capital expenditures in response to these risks. The insurance industry has also been affected by these events and the availability of insurance may decrease. In addition, insurance may have higher deductibles, higher premiums and more restrictive policy terms.

A disruption of the regional electric transmission grid, interstate natural gas pipeline infrastructure or other fuel sources, could negatively impact our business, brand and reputation. Because our facilities are part of an interconnected system, we face the risk of possible loss of business due to a disruption caused by the actions of a neighboring utility.

We also face the risks of possible loss of business due to significant events such as severe storm, severe temperature extremes, wildfires (particularly in Colorado), widespread pandemic, generator or transmission facility outage, pipeline rupture, railroad disruption, operator error, sudden and significant increase or decrease in wind generation or a disruption of work force within our operating systems (or on a neighboring system).

The recent coronavirus outbreak in China is an example of how major catastrophic events throughout the world may disrupt our business. While we are a domestic company, the Company participates in a global supply chain, which includes materials and components that are sourced from China. A prolonged disruption could result in the delay of equipment and materials that may impact our ability to reliably serve our customers.

Disruption due to events such as those noted above could result in a significant decrease in revenues and additional costs to repair assets, which could have a material impact on our results of operations, financial condition or cash flows.

Xcel Energy participates in biennial grid security and emergency response exercises (GridEx). These efforts, led by the NERC, test and further develop the coordination, threat sharing and interaction between utilities and various government agencies relative to potential cyber and physical threats against the nation's electric grid.

A cyber incident or security breach could have a material effect on our business.

We operate in an industry that requires the continued operation of sophisticated information technology, control systems and network infrastructure. In addition, we use our systems and infrastructure to create, collect, use, disclose, store, dispose of and otherwise process sensitive information, including company data, customer energy usage data, and personal information regarding customers, employees and their dependents, contractors, shareholders and other individuals.

The Company's generation, transmission, distribution and fuel storage facilities, information technology systems and other infrastructure or physical assets, as well as information processed in our systems (e.g., information regarding our customers, employees, operations, infrastructure and assets) could be affected by cyber security incidents, including those caused by human error. The utility industry has been the target of several attacks on operational systems and has seen an increased volume and sophistication of cyber security incidents from international activist organizations, Nation States and individuals. Cyber security incidents could harm our businesses by limiting our generating, transmitting and distributing capabilities, delaying our development and construction of new facilities or capital improvement projects to existing facilities, disrupting our customer operations or causing the release of customer information, all of which would likely receive state and federal regulatory scrutiny and could expose us to liability.

Xcel Energy's generation, transmission systems and natural gas pipelines are part of an interconnected system. Therefore, a disruption caused by the impact of a cyber security incident of the regional electric transmission grid, natural gas pipeline infrastructure or other fuel sources of our third-party service providers' operations, could also negatively impact our business.

Our supply chain for procurement of digital equipment may expose software or hardware to these risks and could result in a breach or significant costs of remediation. We are unable to quantify the potential impact of cyber security threats or subsequent related actions. Cyber security incidents and regulatory action could result in a material decrease in revenues and may cause significant additional costs (e.g., penalties, third-party claims, repairs, insurance or compliance) and potentially disrupt our supply and markets for natural gas, oil and other fuels.

We maintain security measures to protect our information technology and control systems, network infrastructure and other assets. However, these assets and the information they process may be vulnerable to cyber security incidents, including asset failure or unauthorized access to assets or information.

A failure or breach of our technology systems or those of our third-party service providers could disrupt critical business functions and may negatively impact our business, our brand, and our reputation. The cyber security threat is dynamic and evolves continually, and our efforts to prioritize network protection may not be effective given the constant changes to threat vulnerability.

Our operating results may fluctuate on a seasonal and quarterly basis and can be adversely affected by milder weather.

Our electric and natural gas utility businesses are seasonal and weather patterns can have a material impact on our operating performance. Demand for electricity is often greater in the summer and winter months associated with cooling and heating. Because natural gas is heavily used for residential and commercial heating, the demand depends heavily upon weather patterns. A significant amount of natural gas revenues are recognized in the first and fourth quarters related to the heating season. Accordingly, our operations have historically generated less revenues and income when weather conditions are milder in the winter and cooler in the summer. Unusually mild winters and summers could have an adverse effect on our financial condition, results of operations or cash flows.

Public Policy Risks

We may be subject to legislative and regulatory responses to climate change, with which compliance could be difficult and costly.

Legislative and regulatory responses related to climate change and new interpretations of existing laws create financial risk as our facilities may be subject to additional regulation at either the state or federal level in the future. Such regulations could impose substantial costs.

We may be subject to climate change lawsuits. An adverse outcome could require substantial capital expenditures and possibly require payment of substantial penalties or damages. Defense costs associated with such litigation can also be significant and could affect results of operations, financial condition or cash flows if such costs are not recovered through regulated rates.

Although the United States has not adopted any international or federal GHG emission reduction targets, many states and localities may continue to pursue climate policies in the absence of federal mandates. The steps Xcel Energy has taken to date to reduce GHG emissions, including energy efficiency measures, adding renewable generation or retiring or converting coal plants to natural gas, occurred under state-endorsed resource plans, renewable energy standards and other state policies. While those actions likely would have put Xcel Energy in a good position to meet federal or international standards being discussed, the lack of federal action does not adversely impact these state-endorsed actions and plans.

If our regulators do not allow us to recover all or a part of the cost of capital investment or the O&M costs incurred to comply with the mandates, it could have a material effect on our results of operations, financial condition or cash flows.

Increased risks of regulatory penalties could negatively impact our business.

The Energy Act increased civil penalty authority for violation of FERC statutes, rules and orders. The FERC can impose penalties of up to $1.3 million per violation per day, particularly as it relates to energy trading activities for both electricity and natural gas. In addition, NERC electric reliability standards and critical infrastructure protection requirements are mandatory and subject to potential financial penalties. Also, the PHMSA, Occupational Safety and Health Administration and other federal agencies have the authority to assess penalties.

In the event of serious incidents, these agencies have become more active in pursuing penalties. Certain states additionally have the authority to impose substantial penalties. If a serious reliability, cyber or safety incident did occur, it could have a material effect on our results of operations, financial condition or cash flows.

Environmental Risks

We are subject to environmental laws and regulations, with which compliance could be difficult and costly.

We are subject to environmental laws and regulations that affect many aspects of our operations, including air emissions, water quality, wastewater discharges and the generation, transport and disposal of solid wastes and hazardous substances. Laws and regulations require us to obtain permits, licenses, and approvals and to comply with a variety of environmental requirements.

Environmental laws and regulations can also require us to restrict or limit the output of facilities or the use of certain fuels, shift generation to lower-emitting facilities, install pollution control equipment, clean up spills and other contamination and correct environmental hazards. Environmental regulations may also lead to shutdown of existing facilities. Failure to meet requirements of environmental mandates may result in fines or penalties. We may be required to pay all or a portion of the cost to remediate (i.e., clean-up) sites where our past activities, or the activities of other parties, caused environmental contamination.

We are subject to mandates to provide customers with clean energy, renewable energy and energy conservation offerings. It could have a material effect on our results of operations, financial condition or cash flows if our regulators do not allow us to recover the cost of capital investment or the O&M costs incurred to comply with the requirements.

In addition, existing environmental laws or regulations may be revised and new laws or regulations may be adopted. We may also incur additional unanticipated obligations or liabilities under existing environmental laws and regulations.

We are subject to physical and financial risks associated with climate change and other weather, natural disaster and resource depletion impacts.

Climate change can create physical and financial risk. Physical risks include changes in weather conditions and extreme weather events.

Our customers' energy needs vary with weather. To the extent weather conditions are affected by climate change, customers' energy use could increase or decrease. Increased energy use due to weather changes may require us to invest in generating assets, transmission and infrastructure. Decreased energy use due to weather changes may result in decreased revenues.

Climate change may impact a region's economy, which could impact our sales and revenues. The price of energy has an impact on the economic health of our communities. The cost of additional regulatory requirements, such as regulation of GHG, could impact the availability of goods and prices charged by our suppliers which would normally be borne by consumers through higher prices for energy and purchased goods. To the extent financial markets view climate change and emissions of GHGs as a financial risk, this could negatively affect our ability to access capital markets or cause us to receive less than ideal terms and conditions.

Severe weather impacts our service territories, primarily when thunderstorms, flooding, tornadoes, wildfires and snow or ice storms occur. Extreme weather conditions in general require system backup and can contribute to increased system stress, including service interruptions. Extreme weather conditions creating high energy demand may raise electricity prices, increasing the cost of energy we provide to our customers.

To the extent the frequency of extreme weather events increases, this could increase our cost of providing service. Periods of extreme temperatures could impact our ability to meet demand. Changes in precipitation resulting in droughts or water shortages could adversely affect our operations. Drought conditions also contribute to the increase in wildfire risk from our electric generation facilities. While we carry liability insurance, given an extreme event, if Xcel Energy was found to be liable for wildfire damages, amounts that potentially exceed our coverage could negatively impact our results of operations, financial condition or cash flows. Drought or water depletion could adversely impact our ability to provide electricity to customers, cause early retirement of units and increase the price paid for energy. We may not recover all costs related to mitigating these physical and financial risks.

ITEM 1B — UNRESOLVED STAFF COMMENTS

None.

ITEM 2 — PROPERTIES

Virtually all of the utility plant property of the operating companies is subject to the lien of their first mortgage bond indentures.

NSP-Minnesota

Station, Location and Unit	Fuel	Installed	MW [(a)]	
Steam:				
A.S. King-Bayport, MN, 1 Unit	Coal	1968	511	
Sherco-Becker, MN				
Unit 1	Coal	1976	680	
Unit 2	Coal	1977	682	
Unit 3	Coal	1987	517	(b)
Monticello, MN, 1 Unit	Nuclear	1971	617	
PI-Welch, MN				
Unit 1	Nuclear	1973	521	
Unit 2	Nuclear	1974	519	
Various locations, 4 Units	Wood/Refuse	Various	36	(c)
Combustion Turbine:				
Angus Anson-Sioux Falls, SD, 3 Units	Natural Gas	1994 - 2005	327	
Black Dog-Burnsville, MN, 3 Units	Natural Gas	1987 - 2018	494	
Blue Lake-Shakopee, MN, 6 Units	Natural Gas	1974 - 2005	453	
High Bridge-St. Paul, MN, 3 Units	Natural Gas	2008	530	
Inver Hills-Inver Grove Heights, MN, 6 Units	Natural Gas	1972	282	
Riverside-Minneapolis, MN, 3 Units	Natural Gas	2009	454	
Various locations, 7 Units	Natural Gas	Various	10	
Wind:				
Border-Rolette County, ND, 75 Units	Wind	2015	148	(d)
Courtenay Wind-Stutsman County, ND, 100 Units	Wind	2016	190	(d)
Foxtail-Dickey County, ND, 75 Units	Wind	2019	150	(d)
Grand Meadow-Mower County, MN, 67 Units	Wind	2008	99	(d)
Lake Benton-Pipestone County, MN, 44 Units	Wind	2019	99	(d)
Nobles-Nobles County, MN, 134 Units	Wind	2010	197	(d)
Pleasant Valley-Mower County, MN, 100 Units	Wind	2015	196	(d)
		Total	7,712	

(a) Summer 2019 net dependable capacity.

(b) Based on NSP-Minnesota's ownership of 59%.

(c) Refuse-derived fuel is made from municipal solid waste.

(d) Values disclosed are the maximum generation levels for these wind units. Capacity is attainable only when wind conditions are sufficiently available (on-demand net dependable capacity is zero).

NSP-Wisconsin

Station, Location and Unit	Fuel	Installed	MW [(a)]	
Steam:				
Bay Front-Ashland, WI, 2 Units	Coal/Wood/Natural Gas	1948 - 1956	41	
French Island-La Crosse, WI, 2 Units	Wood/Refuse	1940 - 1948	16	(b)
Combustion Turbine:				
French Island-La Crosse, WI, 2 Units	Oil	1974	122	
Wheaton-Eau Claire, WI, 5 Units	Natural Gas/Oil	1973	234	
Hydro:				
Various locations, 63 Units	Hydro	Various	135	
		Total	548	

(a) Summer 2019 net dependable capacity.

(b) Refuse-derived fuel is made from municipal solid waste.

PSCo

Station, Location and Unit	Fuel	Installed	MW [(a)]	
Steam:				
Comanche-Pueblo, CO [(b)]				
Unit 1	Coal	1973	325	
Unit 2	Coal	1975	335	
Unit 3	Coal	2010	500	(c)
Craig-Craig, CO, 2 Units [(d)]	Coal	1979 - 1980	82	(e)
Hayden-Hayden, CO, 2 Units	Coal	1965 - 1976	233	(f)
Pawnee-Brush, CO, 1 Unit	Coal	1981	505	
Cherokee-Denver, CO, 1 Unit	Natural Gas	1968	310	
Combustion Turbine:				
Blue Spruce-Aurora, CO, 2 Units	Natural Gas	2003	264	
Cherokee-Denver, CO, 3 Units	Natural Gas	2015	576	
Fort St. Vrain-Platteville, CO, 6 Units	Natural Gas	1972 - 2009	968	
Rocky Mountain-Keenesburg, CO, 3 Units	Natural Gas	2004	580	
Various locations, 6 Units	Natural Gas	Various	171	
Hydro:				
Cabin Creek-Georgetown, CO				
Pumped Storage, 2 Units	Hydro	1967	210	
Various locations, 8 Units	Hydro	Various	25	
Wind:				
Rush Creek, CO, 300 units	Wind	2018	582	(g)
		Total	5,666	

(a) Summer 2019 net dependable capacity.

(b) In 2018, the CPUC approved early retirement of PSCo's Comanche Units 1 and 2 in 2022 and 2025, respectively.

(c) Based on PSCo's ownership of 67%.

(d) Craig Unit 1 is expected to be retired early in 2025.

(e) Based on PSCo's ownership of 10%.

(f) Based on PSCo's ownership of 76% of Unit 1 and 37% of Unit 2.

(g) Values disclosed are the maximum generation levels for these wind units. Capacity is attainable only when wind conditions are sufficiently available (on-demand net dependable capacity is zero).

SPS

Station, Location and Unit	Fuel	Installed	MW [(a)]
Steam:			
Cunningham-Hobbs, NM, 2 Units	Natural Gas	1957 - 1965	189
Harrington-Amarillo, TX, 3 Units	Coal	1976 - 1980	1,018
Jones-Lubbock, TX, 2 Units	Natural Gas	1971 - 1974	486
Maddox-Hobbs, NM, 1 Unit	Natural Gas	1967	112
Nichols-Amarillo, TX, 3 Units	Natural Gas	1960 - 1968	457
Plant X-Earth, TX, 4 Units	Natural Gas	1952 - 1964	411
Tolk-Muleshoe, TX, 2 Units	Coal	1982 - 1985	1,067
Combustion Turbine:			
Cunningham-Hobbs, NM, 2 Units	Natural Gas	1997	209
Jones-Lubbock, TX, 2 Units	Natural Gas	2011 - 2013	334
Maddox-Hobbs, NM, 1 Unit	Natural Gas	1963 - 1976	61
Wind:			
Hale-Plainview, TX, 239 Units	Wind	2019	460 [(b)]
		Total	4,804

(a) Summer 2019 net dependable capacity.

(b) Values disclosed are the maximum generation levels for these wind units. Capacity is attainable only when wind conditions are sufficiently available (on-demand net dependable capacity is zero).

Electric utility overhead and underground transmission and distribution lines (measured in conductor miles) at Dec. 31, 2019:

Conductor Miles	NSP-Minnesota	NSP-Wisconsin	PSCo	SPS
500 KV	2,917	—	—	—
345 KV	13,133	3,337	5,036	9,566
230 KV	2,203	—	12,108	9,784
161 KV	673	1,821	—	—
138 KV	—	—	92	—
115 KV	8,045	1,815	5,055	14,662
Less than 115 KV	86,743	32,816	79,740	26,216

Electric utility transmission and distribution substations at Dec. 31, 2019:

	NSP-Minnesota	NSP-Wisconsin	PSCo	SPS
Quantity	346	204	233	452

Natural gas utility mains at Dec. 31, 2019:

Miles	NSP-Minnesota	NSP-Wisconsin	PSCo	SPS	WGI
Transmission	86	3	2,057	20	11
Distribution	10,518	2,473	22,633	—	—

ITEM 3 — LEGAL PROCEEDINGS

Xcel Energy is involved in various litigation matters in the ordinary course of business. The assessment of whether a loss is probable or is a reasonable possibility, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. Management maintains accruals for losses probable of being incurred and subject to reasonable estimation. Management is sometimes unable to estimate an amount or range of a reasonably possible loss in certain situations, including but not limited to when (1) the damages sought are indeterminate, (2) the proceedings are in the early stages, or (3) the matters involve novel or unsettled legal theories. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution of such matters, including a possible eventual loss.

For current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, would have a material effect on Xcel Energy's financial statements. Unless otherwise required by GAAP, legal fees are expensed as incurred.

See Note 12 to the consolidated financial statements, Item 1 and Item 7 for further information.

ITEM 4 — MINE SAFETY DISCLOSURES

None.

PART II

ITEM 5 — MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES.

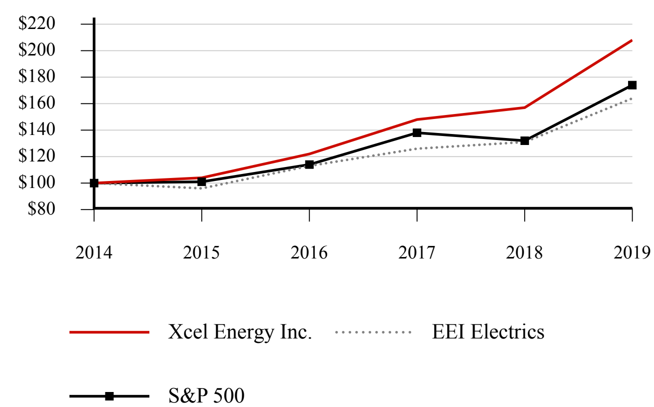
Stock Data

Xcel Energy Inc.'s common stock was listed on the New York Stock Exchange (NYSE) in 2017, but moved to the Nasdaq Global Select Market (Nasdaq) in 2018. The trading symbol is XEL. The number of common stockholders of record as of Feb. 19, 2020 was approximately 54,543.

The following compares our cumulative TSR on common stock with the cumulative TSR of the EEI Investor-Owned Electrics Index and the Standard & Poor's 500 Composite Stock Price Index over the last five years.

The EEI Investor-Owned Electrics Index (market capitalization-weighted) included 40 companies at year-end and is a broad measure of industry performance.

Comparison of Five Year Cumulative Total Return*



* $100 invested on Dec. 31, 2014 in stock or index — including reinvestment of dividends. Fiscal years ended Dec. 31.

Securities Authorized for Issuance Under Equity Compensation Plans

Information required under Item 5 — Securities Authorized for Issuance under Equity Compensation Plans is contained in Xcel Energy's Proxy Statement for its 2020 Annual Meeting of Shareholders, which is incorporated by reference.

Purchases of Equity Securities by Issuer and Affiliated Purchasers

For the quarter ended Dec. 31, 2019, no equity securities that are registered by Xcel Energy Inc. pursuant to Section 12 of the Securities Exchange Act of 1934 were purchased by or on behalf of us or any of our affiliated purchasers.

ITEM 6 — SELECTED FINANCIAL DATA

Selected financial data for Xcel Energy related to the five most recent years ended Dec. 31:

(Millions of Dollars, Millions of Shares, Except Per Share Data)	2019	2018	2017	2016	2015
Operating revenues	$ 11,529	$ 11,537	$ 11,404	$ 11,107	$ 11,024
Operating expenses [(a)]	9,425	9,572	9,181	8,867	9,024
Net income	1,372	1,261	1,148	1,123	984
Earnings available to common shareholders	1,372	1,261	1,148	1,123	984
Diluted earnings per common share	2.64	2.47	2.25	2.21	1.94
Financial information					
Dividends declared per common share	1.62	1.52	1.44	1.36	1.28
Total assets [(b) (c)]	50,448	45,987	43,030	41,155	38,821
Long-term debt [(c) (d)]	17,407	15,803	14,520	14,195	12,399

(a) As a result of adopting ASU No. 2017-07 (*Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost, Topic 715),* $33 million and $26 million of pension costs were retrospectively reclassified from O&M expenses to other income, net on the consolidated statements of income for the years ended Dec. 31, 2017 and Dec. 31, 2016, respectively.

(b) As a result of adopting ASU No. 2015-17 (*Balance Sheet Classification of Deferred Taxes, Topic 740*), $140 million of current deferred income taxes was retrospectively reclassified to long-term deferred income tax liabilities on the consolidated balance sheet as of Dec. 31, 2015.

(c) As a result of adopting ASU No. 2015-03 (*Simplifying the Presentation of Debt Issuance Costs, Subtopic 835-30*), $92 million of deferred debt issuance costs was retrospectively reclassified from other noncurrent assets to long-term debt on the consolidated balance sheet as of Dec. 31, 2015.

(d) As a result of adopting *Leases, Topic 842,* finance lease obligations of $77 million are included in other noncurrent liabilities on the consolidated balance sheet at Dec. 31, 2019. These obligations were included in long-term debt prior to 2019.

ITEM 7 — MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Non-GAAP Financial Measures

The following discussion includes financial information prepared in accordance with GAAP, as well as certain non-GAAP financial measures such as ongoing ROE, electric margin, natural gas margin, ongoing earnings and ongoing diluted EPS. Generally, a non-GAAP financial measure is a measure of a company's financial performance, financial position or cash flows that excludes (or includes) amounts that are adjusted from measures calculated and presented in accordance with GAAP.

Xcel Energy's management uses non-GAAP measures for financial planning and analysis, for reporting of results to the Board of Directors, in determining performance-based compensation, and communicating its earnings outlook to analysts and investors. Non-GAAP financial measures are intended to supplement investors' understanding of our performance and should not be considered alternatives for financial measures presented in accordance with GAAP. These measures are discussed in more detail below and may not be comparable to other companies' similarly titled non-GAAP financial measures.

Ongoing ROE

Ongoing ROE is calculated by dividing the net income or loss of Xcel Energy or each subsidiary, adjusted for certain nonrecurring items, by each entity's average stockholder's equity. We use these non-GAAP financial measures to evaluate and provide details of earnings results.

Electric and Natural Gas Margins

Electric margin is presented as electric revenues less electric fuel and purchased power expenses. Natural gas margin is presented as natural gas revenues less the cost of natural gas sold and transported. Expenses incurred for electric fuel and purchased power and the cost of natural gas are generally recovered through various regulatory recovery mechanisms. As a result, changes in these expenses are generally offset in operating revenues. Management believes electric and natural gas margins provide the most meaningful basis for evaluating our operations because they exclude the revenue impact of fluctuations in these expenses.

These margins can be reconciled to operating income, a GAAP measure, by including other operating revenues, cost of sales-other, O&M expenses, conservation and DSM expenses, depreciation and amortization and taxes (other than income taxes).

Earnings Adjusted for Certain Items (Ongoing Earnings and Ongoing Diluted EPS)

GAAP diluted EPS reflects the potential dilution that could occur if securities or other agreements to issue common stock (i.e., common stock equivalents) were settled. The weighted average number of potentially dilutive shares outstanding used to calculate Xcel Energy Inc.'s diluted EPS is calculated using the treasury stock method. Ongoing earnings reflect adjustments to GAAP earnings (net income) for certain items. Ongoing diluted EPS is calculated by dividing the net income or loss of each subsidiary, adjusted for certain items, by the weighted average fully diluted Xcel Energy Inc. common shares outstanding for the period. Ongoing diluted EPS for each subsidiary is calculated by dividing the net income or loss of such subsidiary, adjusted for certain items, by the weighted average fully diluted Xcel Energy Inc. common shares outstanding for the period.

We use these non-GAAP financial measures to evaluate and provide details of Xcel Energy's core earnings and underlying performance. We believe these measurements are useful to investors to evaluate the actual and projected financial performance and contribution of our subsidiaries. For the years ended Dec. 31, 2019 and Dec. 31, 2018, there were no such adjustments to GAAP earnings and therefore GAAP earnings equal ongoing earnings.

Results of Operations

Diluted EPS for Xcel Energy at Dec. 31:

Diluted Earnings (Loss) Per Share	2019 GAAP and Ongoing Diluted EPS	2018 GAAP and Ongoing Diluted EPS
PSCo	$ 1.11	$ 1.08
NSP-Minnesota	1.04	0.96
SPS	0.51	0.42
NSP-Wisconsin	0.15	0.19
Equity earnings of unconsolidated subsidiaries [(a)]	0.05	0.04
Regulated utility [(b)]	2.86	2.69
Xcel Energy Inc. and other	(0.22)	(0.22)
Total [(b)]	$ 2.64	$ 2.47

(a) Includes income taxes.

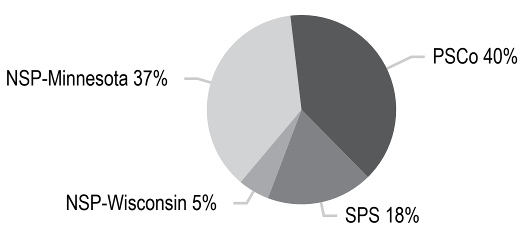
(b) Amounts may not add due to rounding.

Xcel Energy's management believes that ongoing earnings reflects management's performance in operating the Company and provides a meaningful representation of the performance of Xcel Energy's core business. In addition, Xcel Energy's management uses ongoing earnings internally for financial planning and analysis, reporting results to the Board of Directors and when communicating its earnings outlook to analysts and investors.

2019 Comparison with 2018

Xcel Energy — GAAP and ongoing earnings increased $0.17 per share. Earnings increased as a result of higher electric margins primarily due to non-fuel riders and regulatory rate outcomes, higher natural gas margins and lower O&M expenses, primarily offset by lower AFUDC, increased depreciation and interest expenses.

Utility Subsidiaries 2019 GAAP and Ongoing Diluted EPS



PSCo — Earnings increased $0.03 per share for 2019, reflecting higher electric margin due primarily to capital riders and increased natural gas margin attributable to capital riders, weather and sales growth, partially offset by lower AFUDC driven by the Rush Creek wind project that was placed in service in 2018 and higher depreciation, interest and O&M.

NSP-Minnesota — Earnings increased $0.08 per share for 2019, reflecting higher electric margin resulting from regulatory rate outcomes and capital riders and lower O&M, partially offset by increased depreciation.

SPS — Earnings increased $0.09 per share, reflecting higher electric margin attributable to purchased capacity costs, regulatory rate outcomes and demand revenue and higher AFUDC, partially offset by increased interest and depreciation.

NSP-Wisconsin — Earnings decreased $0.04 per share, reflecting lower electric margin, primarily related to sales decline and the impact of unfavorable weather, higher depreciation and lower AFUDC.

Xcel Energy Inc. and other — Xcel Energy Inc. and other primarily includes financing costs at the holding company.

Changes in Diluted EPS

Components significantly contributing to changes in EPS:

2019 vs. 2018

Diluted Earnings (Loss) Per Share	Dec. 31
GAAP and ongoing diluted EPS - 2018	**$ 2.47**
Components of change — 2019 vs. 2018	
Higher electric margins	0.29
Lower ETR [(a)]	0.15
Higher natural gas margins	0.08
Lower O&M	0.02
Higher depreciation and amortization	(0.18)
Higher interest	(0.11)
Lower AFUDC	(0.08)
GAAP and ongoing diluted EPS — 2019	**$ 2.64**

(a) Includes PTCs and timing of tax reform regulatory decisions, which are primarily offset in electric margin.

ROE for Xcel Energy and its utility subsidiaries at Dec. 31:

ROE	2019 GAAP and Ongoing ROE	2018 GAAP and Ongoing ROE
PSCo	8.69%	9.10%
NSP-Minnesota	9.31	8.91
SPS	9.71	9.14
NSP-Wisconsin	8.27	10.77
Operating Companies	9.06	9.14
Xcel Energy	10.78	10.65

Statement of Income Analysis

The following summarizes the items that affected the individual revenue and expense items reported in the consolidated statements of income.

Estimated Impact of Temperature Changes on Earnings — Unusually hot summers or cold winters increase electric and natural gas sales, while mild weather reduces electric and natural gas sales. The estimated impact of weather on earnings is based on the number of customers, temperature variances, the amount of natural gas or electricity historically used per degree of temperature and excludes any incremental related operating expenses that could result due to storm activity or vegetation management requirements. As a result, weather deviations from normal levels can affect Xcel Energy's financial performance.

Degree-day or THI data is used to estimate amounts of energy required to maintain comfortable indoor temperature levels based on each day's average temperature and humidity. HDD is the measure of the variation in the weather based on the extent to which the average daily temperature falls below 65° Fahrenheit. CDD is the measure of the variation in the weather based on the extent to which the average daily temperature rises above 65° Fahrenheit. Each degree of temperature above 65° Fahrenheit is counted as one CDD, and each degree of temperature below 65° Fahrenheit is counted as one HDD. In Xcel Energy's more humid service territories, a THI is used in place of CDD, which adds a humidity factor to CDD. HDD, CDD and THI are most likely to impact the usage of Xcel Energy's residential and commercial customers. Industrial customers are less sensitive to weather.

Normal weather conditions are defined as either the 20-year or 30-year average of actual historical weather conditions. The historical period of time used in the calculation of normal weather differs by jurisdiction, based on regulatory practice. To calculate the impact of weather on demand, a demand factor is applied to the weather impact on sales. Extreme weather variations, windchill and cloud cover may not be reflected in weather-normalized estimates.

Percentage increase (decrease) in normal and actual HDD, CDD and THI:

	2019 vs. Normal	2018 vs. Normal	2019 vs. 2018
HDD	10.4%	2.2%	6.8%
CDD	5.4	26.7	(15.5)
THI	(8.8)	37.3	(33.2)

Weather — Estimated impact of temperature variations on EPS compared with normal weather conditions:

	2019 vs. Normal	2018 vs. Normal	2019 vs. 2018
Retail electric	$ 0.040	$ 0.114	$ (0.074)
Firm natural gas	0.027	0.007	0.020
Total (excluding decoupling)	$ 0.067	$ 0.121	$ (0.054)
Decoupling — Minnesota electric	—	(0.051)	0.051
Total (adjusted for recovery from decoupling)	$ 0.067	$ 0.070	$ (0.003)

Sales Growth (Decline) — Sales growth (decline) for actual and weather-normalized sales:

	2019 vs. 2018				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Actual					
Electric residential	0.1%	(3.5)%	0.3%	(1.8)%	(1.5)%
Electric C&I	(0.6)	(4.0)	3.5	(3.2)	(1.1)
Total retail electric sales	(0.3)	(3.9)	2.8	(2.8)	(1.2)
Firm natural gas sales	12.9	3.6	N/A	(2.0)	8.8

	2019 vs. 2018				
	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
Weather-normalized					
Electric residential	(0.1)%	0.1%	1.9%	1.1%	0.4%
Electric C&I	(0.6)	(3.0)	3.8	(2.6)	(0.5)
Total retail electric sales	(0.3)	(2.1)	3.4	(1.6)	(0.3)
Firm natural gas sales	4.1	1.1	N/A	(2.5)	2.7

Weather-normalized 2019 Electric Sales Growth (Decline)

- PSCo — Residential sales declined due to lower use per customer, partially offset by an increased number of customers. The decline in C&I was mainly due to lower use per customer, primarily led by customers in the food products and service industries, partially offset by growth in the metal mining and fabricated metal and industries. The decrease in customer use was partially offset by an increase in the number of C&I customers;
- NSP-Minnesota — Flat residential sales reflect lower use per customer offset by customer additions. The decline in C&I sales was a result of customer growth being offset by lower use per customer, and certain customers moving to co-generation. Decreased sales to C&I customers were driven by the energy and manufacturing sectors;
- SPS — Residential sales grew largely due to an increase in customers and higher use per customer. C&I sales grew based on higher use per small C&I customer and an overall increase in the number of C&I customers. In addition, the increase in C&I sales was driven by the oil and natural gas industry in the Southeastern New Mexico, Permian Basin area; and
- NSP-Wisconsin — Residential sales growth was primarily attributable to customer additions and more use per customer. The decline in C&I sales was largely due to lower use per customer and decreased sales to the frac sand mining, food and manufacturing sectors, which was partially offset by customer additions.

Weather-normalized 2019 Natural Gas Sales Growth

- Overall natural gas sales reflect an increase in the number of customers combined with higher customer use, particularly C&I at PSCo. This was partially offset by a decline in C&I sales at NSP-Wisconsin, driven by the frac sand mining industry.

Weather-normalized sales for 2020 are projected to increase ~1% over 2019 levels for retail electric and natural gas customers, including the impact of leap year.

Electric Margin

Electric revenues and fuel and purchased power expenses are impacted by fluctuations in the price of natural gas, coal and uranium used in the generation of electricity. However, these price fluctuations have minimal impact on electric margin due to fuel recovery mechanisms that recover fuel expenses. In addition, electric customers receive a credit for PTCs generated in a particular period.

Electric Margin

(Millions of Dollars)	2019 vs. 2018
Non-fuel riders [(a)]	$ 107
Regulatory rate outcomes (Minnesota, New Mexico, North and South Dakota)	95
Implementation of lease accounting standard (offset in interest expense and amortization)	22
Purchased capacity costs	22
Demand revenue	20
Wholesale transmission revenue (net)	11
Timing of tax reform regulatory decisions (offset in income tax and amortization)	(37)
Estimated impact of weather (net of Minnesota decoupling)	(25)
Firm wholesale generation	(20)
Sales declines (excluding weather impact)	(18)
Other (net)	23
Total increase in electric margin	$ 200

(a) Includes approximately $60 million of additional PTC benefit (grossed-up for tax) as compared to 2018, which are credited to customers through various regulatory mechanisms.

Natural Gas Margin

Total natural gas expense varies with changing sales requirements and the cost of natural gas. However, fluctuations in the cost of natural gas has minimal impact on natural gas margin due to cost recovery mechanisms.

Natural Gas Margin

(Millions of Dollars)		2019 vs. 2018
Infrastructure and integrity riders	$	19
Estimated impact of weather		14
Transport sales		7
Retail sales growth		7
Other (net)		7
Total increase in natural gas margin	$	54

Non-Fuel Operating Expenses and Other Items

O&M Expenses — O&M expenses decreased $14 million, or 0.6%, for 2019. Significant changes are summarized below:

(Millions of Dollars)		2019 vs. 2018
Plant generation	$	(20)
Nuclear plant operations and amortization		(8)
Transmission		(7)
Distribution		16
Other (net)		5
Total decrease in O&M expenses	$	(14)

- Plant generation, transmission and distribution costs were lower due to timing of maintenance activities;
- Nuclear plant operations and amortization were lower largely reflecting improved operating efficiencies and reduced refueling outage costs; and
- Distribution expenses in 2019 were higher than 2018 due to storms, labor and overtime incurred primarily in the first six months of 2019.

Depreciation and Amortization — Depreciation and amortization increased $123 million, or 7%, for 2019. The increase was primarily driven by the Rush Creek, Hale, Foxtail and Lake Benton wind farms going into service, natural gas and distribution/transmission replacements, and various software solutions. These increases were partially offset by higher levels of accelerated amortization of PSCo's prepaid pension asset in 2018.

Taxes (Other than Income Taxes) — Taxes (other than income taxes) increased $13 million, or 2.3%, for 2019. The increase was primarily due to higher property taxes in Colorado and Minnesota (net of deferred amounts).

AFUDC, Equity and Debt — AFUDC decreased $42 million for 2019. The decrease was primarily due to the Rush Creek wind project being placed in-service in 2018, partially offset by the Hale wind project, which went into service in June 2019, and other capital investments.

Interest Charges — Interest charges increased $73 million, or 10.4%, for 2019. The increase was primarily due to higher debt levels to fund capital investments, changes in short-term interest rates and implementation of lease accounting standard (offset in electric margin).

Income Taxes — Income taxes decreased $53 million for 2019, primarily driven by an increase in wind PTCs. Wind PTCs are credited to customers (recorded as a reduction to revenue) and do not have a material impact on net income. These were partially offset by higher pretax earnings in 2019 and ITCs in 2018. The ETR was 8.5% for 2019 compared with 12.6% for the same period in 2018, largely due to the adjustments above.

Xcel Energy Inc. and Other Results

Net income and diluted EPS contributions of Xcel Energy Inc. and its nonregulated businesses:

	Contribution (Millions of Dollars)			
		2019		2018
Xcel Energy Inc. financing costs	$	(128)	$	(110)
Eloigne [(a)]		1		—
Xcel Energy Inc. taxes and other results		12		(5)
Total Xcel Energy Inc. and other costs	$	(115)	$	(115)

	Contribution (Diluted Earnings (Loss) Per Share)			
		2019		2018
Xcel Energy Inc. financing costs	$	(0.21)	$	(0.21)
Eloigne [(a)]		—		—
Xcel Energy Inc. taxes and other results		(0.01)		(0.01)
Total Xcel Energy Inc. and other costs	$	(0.22)	$	(0.22)

(a) Amounts include gains or losses associated with sales of properties held by Eloigne.

Xcel Energy Inc.'s results include interest charges, which are incurred at Xcel Energy Inc. and are not directly assigned to individual subsidiaries.

2018 Comparison with 2017

A discussion of changes in Xcel Energy's results of operations and liquidity and capital resources from the year ended Dec. 31, 2017 to Dec. 31, 2018 can be found in Part II, "Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations" of our Annual Report on Form 10-K for the fiscal year 2018, which was filed with the SEC on Feb. 22, 2019. However, such discussion is not incorporated by reference into, and does not constitute a part of, this Annual Report on Form 10-K.

Public Utility Regulation

The FERC and various state and local regulatory commissions regulate Xcel Energy Inc.'s utility subsidiaries and WGI. Xcel Energy is subject to rate regulation by state utility regulatory agencies, which have jurisdiction with respect to the rates of electric and natural gas distribution companies in Minnesota, North Dakota, South Dakota, Wisconsin, Michigan, Colorado, New Mexico, and Texas.

Rates are designed to recover plant investment, operating costs and an allowed return on investment. Our utility subsidiaries request changes in rates for utility services through filings with governing commissions. Changes in operating costs can affect Xcel Energy's financial results, depending on the timing of rate case filings and implementation of final rates. Other factors affecting rate filings are new investments, sales, conservation and DSM efforts, and the cost of capital.

In addition, the regulatory commissions authorize the ROE, capital structure and depreciation rates in rate proceedings. Decisions by these regulators can significantly impact Xcel Energy's results of operations.

See Rate Matters within Note 12 to the consolidated financial statements for further information.

NSP-Minnesota

Summary of Regulatory Agencies / RTO and Areas of Jurisdiction

Regulatory Body / RTO	Additional Information
MPUC [(a)]	Retail rates, services, security issuances, property transfers, mergers, disposition of assets, affiliate transactions, and other aspects of electric and natural gas operations. Reviews and approves IRPs for meeting future energy needs. Certifies the need and siting for generating plants greater than 50 MW and transmission lines greater than 100 KV in Minnesota. Reviews and approves natural gas supply plans. Pipeline safety compliance.
NDPSC [(a)]	Retail rates, services and other aspects of electric and natural gas operations. Regulatory authority over generation and transmission facilities, along with the siting and routing of new generation and transmission facilities in North Dakota. Pipeline safety compliance.
SDPUC	Retail rates, services and other aspects of electric operations. Regulatory authority over generation and transmission facilities, along with the siting and routing of new generation and transmission facilities in South Dakota. Pipeline safety compliance.
FERC	Wholesale electric operations, hydroelectric licensing, accounting practices, wholesale sales for resale, transmission of electricity in interstate commerce, compliance with NERC electric reliability standards, asset transfers and mergers, and natural gas transactions in interstate commerce.
MISO	NSP-Minnesota is a transmission owning member of the MISO RTO and operates within the MISO RTO and wholesale markets. NSP-Minnesota makes wholesale sales in other RTO markets at market-based rates. NSP-Minnesota and NSP-Wisconsin also make wholesale electric sales at market-based prices to customers outside of their balancing authority as jointly authorized by the FERC.
DOT	Pipeline safety compliance.
Minnesota Office of Pipeline Safety	Pipeline safety compliance.

(a) *Jurisdictional Cost Recovery Allocation* — In December 2016, NSP-Minnesota filed a resource treatment framework with the NDPSC and MPUC to allow NSP-Minnesota's operations in North Dakota and Minnesota to gradually become more independent of one another. The filing identified two options: a legal separation, creating a separate North Dakota operating company; or a pseudo-separation, which maintains the current corporate structure but directly assigns costs and benefits of each resource to the jurisdiction that supports it. Docket remains under consideration by the NDPSC.

Recovery Mechanisms

Mechanism	Additional Information
CIP Rider [(a)]	Recovers costs of conservation and DSM programs.
EIR	Recovers costs of environmental improvement projects.
RDF	Allocates money collected from customers to support research and development of emerging renewable energy projects and technologies.
RES	Recovers cost of renewable generation in Minnesota.
RER	Recovers the cost of renewable generation in North Dakota.
SEP	Recovers costs related to various energy policies approved by the Minnesota legislature.
TCR	Recovers costs for investments in electric transmission and distribution grid modernization.
Infrastructure Rider	Recovers costs for investments in generation and incremental property taxes in South Dakota.
FCA [(b)]	Minnesota, North Dakota and South Dakota include a FCA for monthly billing adjustments to recover changes in prudently incurred costs of fuel related items and purchased energy. Capacity costs are recovered through base rates and are not recovered through the FCA. MISO costs are generally recovered through either the FCA or base rates.
PGA	Provides for prospective monthly rate adjustments for costs of purchased natural gas, transportation and storage service. Includes a true-up process for difference between projected and actuals costs.
GUIC Rider	Recovers costs for transmission and distribution pipeline integrity management programs, including: funding for pipeline assessments, deferred costs for sewer separation and pipeline integrity management programs.

(a) Minnesota state law requires NSP-Minnesota to invest 2% of its state electric revenues and 0.5% of its state gas revenues in CIP. These costs are recovered through an annual cost-recovery mechanism.

(b) In 2017, the MPUC changed the FCA process in Minnesota, which will implemented in 2020. Under the new process, each month utilities would collect amounts equal to the baseline cost of energy set at the start of the plan year (base would be reset annually). Monthly variations to the baseline costs would be tracked and netted over a 12-month period. Utilities would issue refunds above the baseline costs and could seek recovery of any overage.

Pending and Recently Concluded Regulatory Proceedings

Mechanism	Utility Service	Amount Requested (in millions)	Filing Date	Approval	Additional Information
					MPUC
2018 TCR	Electric	$98	November 2017	Received	In November 2019, the MPUC issued an order setting an ROE of 9.06% and recovery of 2017-2018 expenses related to advanced grid investments.
2020 TCR	Electric	$82	November 2019	Pending	In November 2019, NSP-Minnesota filed the 2020 TCR Rider. The filing included an ROE of 9.06%. Timing of an MPUC ruling is uncertain.
2019 GUIC	Natural Gas	$29	November 2018	Pending	In November 2018, NSP-Minnesota filed the 2019 GUIC Rider with the MPUC. The filing included an ROE of 10.25%. Timing of an MPUC ruling is uncertain.
2020 GUIC	Natural Gas	$21	November 2019	Pending	In November 2019, NSP-Minnesota filed the 2020 GUIC Rider with the MPUC. The filing included an ROE of 9.04%. Timing of an MPUC ruling is uncertain.
2018 RES	Electric	$23	November 2017	Received	In November 2019, the MPUC approved an order setting an ROE of 9.06%.
2020 RES	Electric	$102	November 2019	Pending	In November 2019, NSP-Minnesota filed the 2020 RES Rider with the MPUC. The requested amount includes a true up for the 2019 rider of $38 million and the 2020 requested amount of $64 million. The filing included an ROE of 9.06%. Timing of an MPUC ruling is uncertain.

Minnesota Electric Rate Case and Alternative Petition — In November 2019, NSP-Minnesota filed a three-year electric rate case with the MPUC. The proposed electric rates reflect a three-year increase in revenues of approximately $201.4 million (6.5%) in 2020, with subsequent incremental increases of $146.4 million (4.8%) in 2021 and $118.3 million (3.9%) in 2022. The rate case is based on a requested ROE of 10.2%, a 52.5% equity ratio, an average electric rate base of $9.0 billion for 2020, $9.3 billion for 2021 and $9.8 billion for 2022.

In addition, NSP-Minnesota requested interim rates, subject to refund, of $122.0 million to be implemented in January 2020 and an incremental $144.0 million to be implemented in January 2021.

NSP-Minnesota also filed a stay-out petition, in which NSP-Minnesota would withdraw its electric rate case and refrain from filing another rate case for one year if the MPUC were to approve an extension of true-up mechanisms for sales, capital and property taxes. NSP-Minnesota also requested that the MPUC delay any increase to the Nuclear Decommissioning Trust annual accrual until 2021.

In December 2019, the MPUC verbally approved the stay-out petition including extension of the sales, capital and property tax true-up mechanisms and the delay of any increase to the Nuclear Decommissioning Trust annual accrual until Jan. 1, 2021.

MEC Acquisition — In November 2018, NSP-Minnesota reached an agreement with Southern Power Company (a subsidiary of Southern Company) to purchase MEC, a 760 MW natural gas combined cycle facility, for approximately $650 million.

In September 2019, the MPUC denied NSP-Minnesota's request to purchase MEC as a rate base asset. In January 2020, the MPUC approved Xcel Energy's plan to acquire MEC as a non-regulated investment and step into the terms of the existing PPAs with NSP-Minnesota. A newly formed non-regulated subsidiary of Xcel Energy completed the transaction to purchase MEC on Jan. 17, 2020.

Minnesota Resource Plan — In July 2019, NSP-Minnesota filed its Minnesota resource plan, which runs through 2034. The plan would result in an 80% carbon reduction by 2030 (from 2005) and puts NSP-Minnesota on a path to achieving its vision of being 100% carbon-free by 2050. The preferred plan includes the following:

- Extends the life of the Monticello nuclear plant from 2030 to 2040;
- Continues to run PI through current end of life (2033 and 2034);
- Includes the MEC acquisition and construction of the Sherco combined cycle natural gas plant;
- Includes the early retirement of the King coal plant (511 MW) in 2028 and the Sherco 3 coal plant (517 MW) in 2030;
- Adds approximately 1,700 MW of firm peaking (combustion turbine, pumped hydro, battery storage, demand response, etc.);
- Adds approximately 1,200 MW of wind replacement; and
- Adds approximately 4,000 MW of solar.

Intervening parties will provide recommendations and comments on the resource plan. Following the MPUC's denial of its request to purchase MEC, NSP-Minnesota will provide updates to remove its ownership of MEC from the preferred plan. The MPUC required NSP-Minnesota to update its filing to address issues related to its decision on MEC, including certain new modeling scenarios. An updated filing is required by April 1, 2020. The MPUC is anticipated to make a final decision on the resource plan in the first half of 2021.

Jeffers Wind and Community Wind North Repowering Acquisition — In October 2019, the MPUC approved NSP-Minnesota's request to acquire the Jeffers and Community Wind North wind facilities in western Minnesota from Longroad Energy. The wind farms will have approximately 70 MW of capacity after being repowered. The repowering is expected to be completed by December 2020 and qualify for the full PTC. The $135 million asset acquisition is projected to provide customer savings of approximately $7 million over the life of the facilities.

Mower Wind Facility — In August 2019, NSP-Minnesota filed a petition with the MPUC to acquire the Mower wind facility from affiliates of NextEra Energy, Inc. for an undisclosed amount. The Mower facility is located in southeastern Minnesota and is currently contracted under a PPA with NSP-Minnesota through 2026. Mower is expected to continue to have approximately 99 MW of capacity following a planned repowering. The acquisition would occur after repowering, which is expected to be complete in 2020 and qualify for the full PTC. NSP-Minnesota will need approval from both the MPUC and FERC to complete the transaction. NSP-Minnesota filed reply comments addressing the DOC's concerns with the transaction in February 2020.Timing of MPUC and FERC decisions are uncertain.

Purchased Power Arrangements and Transmission Service Provider

NSP-Minnesota expects to use power plants, power purchases, CIP/DSM options, new generation facilities and expansion of power plants to meet its system capacity requirements.

Purchased Power — NSP-Minnesota has contracts to purchase power from other utilities and IPPs. Long-term purchased power contracts for dispatchable resources typically require a capacity and an energy charge. NSP-Minnesota makes short-term purchases to meet system requirements, replace company owned generation, meet operating reserve obligations or obtain energy at a lower cost.

PPA Terminations and Amendments — In June 2018, NSP-Minnesota terminated the Benson and Laurentian PPAs, and purchased the Benson biomass facility. As a result, a $103 million regulatory asset was recognized for the costs of the Benson transaction. For Laurentian, a regulatory asset of $109 million was recognized for annual termination payments/obligations. Regulatory approvals provide for recovery of the Benson regulatory asset over 10 years and Laurentian termination payments as they occur (over six years). Termination of the PPAs is expected to save customers over $600 million throughout the next 10 years.

Purchased Transmission Services — NSP-Minnesota and NSP-Wisconsin have contracts with MISO and other regional transmission service providers to deliver power and energy to their customers.

Minnesota State ROFR Statute Complaint — In September 2017, LSP Transmission filed a complaint in the Minnesota District Court against the Minnesota Attorney General, MPUC and DOC. The complaint was in response to MISO assigning NSP-Minnesota and ITC Midwest, LLC to jointly own a new 345 KV transmission line from Mankato to Winnebago, Minnesota.

The project was estimated to cost $108 million and projected to be in-service by the end of 2021. It was assigned to NSP-Minnesota and ITC Midwest as the incumbent utilities, consistent with a Minnesota state ROFR statute. The complaint challenged the constitutionality of the statute and is seeking declaratory judgment that the statute violates the Commerce Clause of the U.S. Constitution and should not be enforced. The Minnesota state agencies and NSP-Minnesota filed motions to dismiss.

In June 2018, the Minnesota District Court granted the defendants' motions to dismiss with prejudice. LSP Transmission filed an appeal in July 2018. In September 2019, the estimate was updated to approximately $140 million, due to various changes in build plans. In October 2019, oral arguments were held with the Eighth Circuit Court of Appeals. A decision is expected in the first or second quarter of 2020.

Nuclear Power Operations and Waste Disposal

Nuclear power plant operations produce gaseous, liquid and solid radioactive wastes, which are covered by federal regulation. High-level radioactive wastes primarily include used nuclear fuel. Low-level waste consists primarily of demineralizer resins, paper, protective clothing, rags, tools and equipment contaminated through use.

NRC Regulation — The NRC regulates nuclear operations. Costs of complying with NRC requirements can affect both operating expenses and capital investments of the plants. NSP-Minnesota has obtained recovery of these compliance costs and expects to recover future compliance costs.

Low-Level Waste Disposal — Low level waste disposal from Monticello and PI is disposed at the Clive facility located in Utah and the Waste Control Specialists facility in Texas. NSP-Minnesota has storage capacity available on-site at PI and Monticello which would allow both plants to continue to operate until the end of their current licensed lives if of-site low-level waste disposal facilities become unavailable.

High-Level Radioactive Waste Disposal — The federal government has responsibility to permanently dispose domestic spent nuclear fuel and other high-level radioactive wastes. The Nuclear Waste Policy Act requires the DOE to implement a program for nuclear high-level waste management. This includes the siting, licensing, construction and operation of a repository for spent nuclear fuel from civilian nuclear power reactors and other high-level radioactive wastes at a permanent federal storage or disposal facility. The federal government has been evaluating a nuclear geologic repository at Yucca Mountain, Nevada for many years. Currently, there are no definitive plans for a permanent federal storage facility site.

Nuclear Spent Fuel Storage — NSP-Minnesota has interim on-site storage for spent nuclear fuel at its Monticello and PI nuclear generating plants. Authorized storage capacity is sufficient to allow NSP-Minnesota to operate until the end of the operating licenses in 2030 for Monticello, 2033 for PI Unit 1, and 2034 for PI Unit 2. Authorizations for additional spent fuel storage capacity may be required at each site to support either continued operation or decommissioning if the federal government does not commence storage operations.

Wholesale and Commodity Marketing Operations

NSP-Minnesota conducts wholesale marketing operations, including the purchase and sale of electric capacity, energy, ancillary services and energy-related products. NSP-Minnesota uses physical and financial instruments to minimize commodity price and credit risk and hedge sales and purchases.

NSP-Minnesota also engages in trading activity unrelated to hedging. Sharing of any margins is determined through state regulatory proceedings as well as the operation of the FERC approved JOA. NSP-Minnesota does not serve any wholesale requirements customers at cost-based regulated rates.

NSP-Wisconsin

Summary of Regulatory Agencies / RTO and Areas of Jurisdiction

Regulatory Body / RTO	Additional Information
PSCW	Retail rates, services and other aspects of electric and natural gas operations. Certifies the need for new generating plants and electric transmission lines before the facilities may be sited and built. The PSCW has a biennial base rate filing requirement. By June of each odd numbered year, NSP-Wisconsin must submit a rate filing for the test year beginning the following January. Pipeline safety compliance.
MPSC	Retail rates, services and other aspects of electric and natural gas operations. Certifies the need for new generating plants and electric transmission lines before the facilities may be sited and built. Pipeline safety compliance.
FERC	Wholesale electric operations, hydroelectric generation licensing, accounting practices, wholesale sales for resale, transmission of electricity in interstate commerce, compliance with NERC electric reliability standards, asset transactions and mergers and natural gas transactions in interstate commerce.
MISO	NSP-Wisconsin is a transmission owning member of the MISO RTO that operates within the MISO RTO and wholesale energy market. NSP-Wisconsin and NSP-Minnesota are jointly authorized by the FERC to make wholesale electric sales at market-based prices.
DOT	Pipeline safety compliance.

Recovery Mechanisms

Mechanism	Additional Information
Annual Fuel Cost Plan [(a)]	NSP-Wisconsin does not have an automatic electric fuel adjustment clause. Under Wisconsin rules, utilities submit a forward-looking annual fuel cost plan to the PSCW. Once the PSCW approves the plan, utilities defer the amount of any fuel cost under-recovery or over-recovery in excess of a 2% annual tolerance band, for future rate recovery or refund. Approval of a fuel cost plan and any rate adjustment for refund or recovery of deferred costs is determined by the PSCW. Rate recovery of deferred fuel cost is subject to an earnings test based on the most recently authorized ROE. Under-collections that exceed the 2% annual tolerance band may not be recovered if the utility earnings for that year exceed the authorized ROE.
Power Supply Cost Recovery Factors	NSP-Wisconsin's retail electric rate schedules for Michigan customers include power supply cost recovery factors, based on 12-month projections. After each 12-month period, a reconciliation is submitted whereby over-recoveries are refunded and any under-recoveries are collected from customers.
Wisconsin Energy Efficiency Program	The primary energy efficiency program is funded by the utilities, but operated by independent contractors subject to oversight by the PSCW and utilities. NSP-Wisconsin recovers these costs from customers.
PGA	NSP-Wisconsin has a retail PGA cost-recovery mechanism for Wisconsin to recover the actual cost of natural gas and transportation and storage services.
Natural Gas Cost-Recovery Factor (MI)	NSP-Wisconsin's natural gas rates for Michigan customers include a natural gas cost-recovery factor, based on 12-month projections and trued-up to actual amounts on an annual basis.

(a) NSP-Wisconsin's electric fuel costs were lower than authorized in rates and outside the 2% annual tolerance band in 2019. Under the fuel cost recovery rules, NSP-Wisconsin retained the $3.3 million of over-recovered fuel costs (amounts within annual tolerance band) and deferred $9.7 million (amounts in excess of annual tolerance band) as a regulatory liability. NSP-Wisconsin plans to file a reconciliation of 2019 fuel costs with the PSCW by March 2020.

Pending and Recently Concluded Regulatory Proceedings

Mechanism	Utility Service	Amount Requested (in millions)	Filing Date	Approval	Additional Information
			PSCW		
Rate Case	Electric & Natural Gas	N/A	May 2019	Received	In May 2019, NSP-Wisconsin filed an application with the PSCW seeking no change to base electric rates through Dec. 31, 2021; and a $3.2 million (4.6%) decrease to base natural gas rates, effective Jan. 1, 2020, and no additional changes to base natural gas rates through Dec. 31, 2021. The settlement is based on an ROE of 10.0% and an equity ratio of 52.5%. In September 2019, the PSCW issued an interim order approving the settlement agreement as filed with one minor modification, to remove the deferral of pension settlement accounting costs for 2021. A final order was received in December 2019.

Purchased Power and Transmission Services

Purchased Power — Through the Interchange Agreement, NSP-Wisconsin receives power purchased by NSP-Minnesota from other utilities and independent power producers. Long-term purchased power contracts for dispatchable resources typically require a capacity charge and an energy charge. NSP-Minnesota makes short-term purchases to meet system requirements, replace company owned generation, meet operating reserve obligations or obtain energy at a lower cost.

Purchased Transmission Services — NSP-Minnesota and NSP-Wisconsin have contracts with MISO and other regional transmission service providers to deliver power and energy to their customers.

Wholesale and Commodity Marketing Operations

NSP-Wisconsin does not serve any wholesale requirements customers at cost-based regulated rates.

PSCo

Summary of Regulatory Agencies / RTO and Areas of Jurisdiction

Regulatory Body / RTO	Additional Information
CPUC	Retail rates, accounts, services, issuance of securities and other aspects of electric and natural gas operations. Pipeline safety compliance.
FERC	Wholesale electric operations, accounting practices, hydroelectric licensing, wholesale sales for resale, transmission of electricity in interstate commerce, compliance with the NERC electric reliability standards, asset transactions and mergers and natural gas transactions in interstate commerce. Wholesale electric sales at cost-based prices to customers inside PSCo's balancing authority area and at market-based prices to customers outside PSCo's balancing authority area. PSCo holds a FERC certificate that allows it to transport natural gas in interstate commerce without PSCo becoming subject to full FERC jurisdiction.
RTO	PSCo is not presently a member of an RTO and does not operate within an RTO energy market. However, PSCo does make certain sales to other RTO's, including SPP and participates in a joint dispatch agreement with neighboring utilities.
DOT	Pipeline safety compliance.

Recovery Mechanisms

Mechanism	Additional Information
ECA	Recovers fuel and purchased energy costs. Short-term sales margins are shared with customers through the ECA. The ECA is revised quarterly.
PCCA	Recovers purchased capacity payments.
SCA	Recovers difference between actual fuel costs and costs recovered under steam service rates. The SCA rate is revised quarterly.
DSMCA	Recovers DSM, interruptible service costs and performance initiatives for achieving energy savings goals.
RESA	Recovers the incremental costs of compliance with the RES with a maximum of 2% of the customer's bill.
WCA	Recovers costs for customers who choose renewable resources.
TCA	Recovers costs for transmission investment outside of rate cases.
CACJA	Recovers costs associated with the CACJA.
FCA	PSCo recovers fuel and purchased energy costs from wholesale electric customers through a fuel cost adjustment clause approved by the FERC. Wholesale customers pay production costs through a forecasted formula rate subject to true-up.
GCA	Recovers costs of purchased natural gas and transportation and is revised quarterly to allow for changes in natural gas rates.
PSIA	Recovers costs for transmission and distribution pipeline integrity management programs.

Pending and Recently Concluded Regulatory Proceedings

Mechanism	Utility Service	Amount Requested (in millions)	Filing Date	Approval	Additional Information
					CPUC
Rate Case	Steam	$7	January 2019	Received	In September 2019, the CPUC approved PSCo's Settlement Agreement with CPUC Staff and the City of Denver. The settlement reflects an ROE of 9.67% for AFUDC purposes, an equity ratio of 56.04% and utilization of tax reform benefits. The first stepped increase went into effect Oct. 1, 2019, with full rates effective Oct. 1, 2020.
Rate Case Appeal	Natural Gas	N/A	April 2019	Pending	In April 2019, PSCo filed an appeal seeking judicial review of the CPUC's prior ruling regarding PSCo's last natural gas rate case (approved in December 2018). Appeal requests review of the following: denial of a return on the prepaid pension and retiree medical assets; the use of a capital structure that is not based on the actual historical test year level; and the use of an average rate base methodology rather than a year-end rate base methodology. Timeline on a final ruling is unknown.
DSM Incentive	Electric & Natural Gas	$12	April 2019	Received	PSCo earned an electric and natural gas DSM incentive of $9 million and $3 million, respectively, for achieving its 2018 savings goals.

PSCo — Electric Rate Case — In October 2019, PSCo filed rebuttal testimony with the CPUC requesting a net rate increase of $108 million. This is based on a $353 million increase offset by $245 million of previously authorized costs currently recovered through various rider mechanisms. The request was based on a ROE of 10.20%, an equity ratio of 55.61% and a current test year, which includes certain forecasted plant additions through December 2019.

In December 2019, the CPUC held deliberations and on Feb. 11, 2020 issued a written decision approving a current test year ended Aug. 31, 2019, a 9.3% ROE, an equity ratio of 55.61%, implementation of decoupling in 2020 and other items. This resulted in an estimated $35 million net base rate revenue increase.

Revenue Request (Millions of Dollars)		2020
Company filed rebuttal	$	353
ROE		(55)
Impact of change in test year		(17)
Property tax expense		15
Rate base adjustments		(11)
Capital structure		(5)
Total proposed revenue change		280
Estimated impact of previously authorized costs (existing riders)		245
Net revenue change	**$**	**35**

Final rates are expected to be implemented in February 2020. PSCo currently intends to file an application for rehearing/reconsideration in the first quarter of 2020.

PSCo — Gas Rate Case — On Feb. 5, 2020, PSCo filed a request with the CPUC seeking a net increase to retail gas rates of $127 million, reflecting a $145 million increase in base rate revenue, which is partially offset by $18 million previously authorized through the PSIA rider mechanism. The request is based on a test year that incorporates actual capital and expenses as of Sept. 30, 2019, adjusted for known and measurable differences for the 12-month period ended Sept. 30, 2020, a 9.95% ROE and an equity ratio of 55.81%. Proposed effective date is Nov. 1, 2020.

Revenue Request (Millions of Dollars)		**2020**
Capital additions (through Sept. 30, 2019)	$	62
Forecasted capital additions (through Sept. 30, 2020)		33
Sales growth (includes amounts forecasted through Sept. 30, 2020)		(29)
Operations and maintenance, amortization and other expenses		29
Property tax expense		19
Cost of capital		8
Updated depreciation rates		5
Net increase to revenue		**127**
Previously authorized costs:		
Transfer PSIA rider costs to base rates		18
Total base request	**$**	**145**
Expected year-end rate base	**$**	**2,236**

The request reflects $1.3 billion of capital additions since the 2016 test year used to set current rates. Capital investments are made to maintain the safety and reliability of the natural gas system, along with investments to connect new customers and perform mandated infrastructure relocation work.

Timing of a CPUC ruling is expected in the second half of 2020.

Resource Plan

CEP — In September 2018, the CPUC approved PSCo's CEP portfolio, which included the retirement of two coal-fired generation units, Comanche Unit 1 (in 2022) and Comanche Unit 2 (in 2025), and the following additions:

	Total Capacity	**PSCo's Ownership**
Wind generation	1,100 MW	500 MW
Solar generation	700 MW	—
Battery storage	275 MW	—
Natural gas generation	380 MW	380 MW

PSCo's investment is expected to be approximately $1 billion, including transmission to support the increase in renewable generation.

CPCNs were granted by the CPUC for the Shortgrass Substation in February 2019, and for the 500 MW Cheyenne Ridge wind farm and 345 KV generation tie line in April 2019.

A CPCN for the acquisitions of the Valmont and Manchief natural gas generation facilities was filed in July 2019, and a settlement on those acquisitions was reached with CPUC Staff and the Colorado Office of Consumer Counsel in January 2020, pending a CPUC decision expected in approximately the second quarter of 2020.

A CPCN for voltage control facilities was also filed with the CPUC in December 2019, with another expected to follow in approximately the first quarter of 2020 for network transmission upgrades required for the CEP portfolio.

Purchased Power and Transmission Service Providers

PSCo expects to meet its system capacity requirements through electric generating stations, power purchases, new generation facilities, DSM options and expansion of generation plants.

Purchased Power — PSCo purchases power from other utilities and IPPs. Long-term purchased power contracts for dispatchable resources typically require capacity and energy charges. It also contracts to purchase power for both wind and solar resources. PSCo makes short-term purchases to meet system load and energy requirements, replace owned generation, meet operating reserve obligations, or obtain energy at a lower cost.

Purchased Transmission Services — In addition to using its own transmission system, PSCo has contracts with regional transmission service providers to deliver energy to its customers.

Boulder Municipalization

In 2011, Boulder passed a ballot measure authorizing the formation of an electric municipal utility, subject to certain conditions. Subsequently, there have been various legal proceedings in multiple venues with jurisdiction over Boulder's plan. In 2014, the Boulder City Council passed an ordinance to establish an electric utility. PSCo challenged the formation of this utility and the Colorado Court of Appeals ruled in PSCo's favor, vacating a lower court decision. In June 2018, the Colorado Supreme Court rejected Boulder's request to dismiss the case and remanded it to the Boulder District Court. The case was then settled in June 2019 after Boulder agreed to repeal the ordinance establishing the utility.

Boulder has filed multiple separation applications with the CPUC, which have been challenged by PSCo and other intervenors. In September 2017, the CPUC issued a written decision, agreeing with several key aspects of PSCo's position. The CPUC has approved the designation of some electrical distribution assets for transfer, subject to Boulder completing certain filings.

In the fourth quarter of 2018, the Boulder City Council also adopted an Ordinance authorizing Boulder to begin negotiations for the acquisition of certain property or to otherwise condemn that property after Feb. 1, 2019. In the first quarter of 2019, Boulder sent PSCo a notice of intent to acquire certain electric distribution assets. In the third quarter of 2019, Boulder filed its condemnation litigation, which was later dismissed by the Boulder District Court in September 2019 on the grounds that Boulder had not completed the pre-requisite CPUC process and filings. Boulder is currently appealing this order. In October 2019, the CPUC approved the subsequent filings regarding asset transfers outside of substations, reaffirmed its 2017 decision on assets outside of substations and closed the CPUC proceeding.

In December 2019, Boulder filed a new condemnation action despite its ongoing appeal of the last condemnation case. PSCo subsequently filed a motion to dismiss or stay the new condemnation action. In February 2020, Boulder filed an application under section 210 of the Federal Power Act asking FERC to order PSCo to interconnect its facilities with a future Boulder municipal utility under Boulder's preferred terms and conditions.

Wholesale and Commodity Marketing Operations

PSCo conducts various wholesale marketing operations, including the purchase and sale of electric capacity, energy, ancillary services and energy related products. PSCo uses physical and financial instruments to minimize commodity price and credit risk and hedge sales and purchases. PSCo also engages in trading activity unrelated to hedging. Sharing of any margin is determined through state regulatory proceedings as well as the operation of the FERC approved JOA.

SPS

Summary of Regulatory Agencies / RTO and Areas of Jurisdiction

Regulatory Body / RTO	Additional Information
PUCT	Retail electric operations, rates, services, construction of transmission or generation and other aspects of SPS' electric operations. The municipalities in which SPS operates in Texas have original jurisdiction over rates in those communities. The municipalities' rate setting decisions are subject to PUCT review.
NMPRC	Retail electric operations, retail rates and services and the construction of transmission or generation.
FERC	Wholesale electric operations, accounting practices, wholesale sales for resale, the transmission of electricity in interstate commerce, compliance with NERC electric reliability standards, asset transactions and mergers, and natural gas transactions in interstate commerce.
SPP RTO and SPP IM Wholesale Market	SPS is a transmission-owning member of the SPP RTO and operates within the SPP RTO and SPP IM wholesale market. SPS is authorized to make wholesale electric sales at market-based prices.

Recovery Mechanisms

Mechanism	Additional Information
DCRF	Recovers distribution costs not included in rates in Texas.
EECRF	Recovers costs for energy efficiency programs in Texas.
Energy Efficiency Rider	Recovers costs for energy efficiency programs in New Mexico.
FPPCAC	Adjusts monthly to recover actual fuel and purchased power costs in New Mexico. In October 2019, SPS filed an application to the NMPRC to approve SPS' continued use of its FPPCAC and for reconciliation of fuel costs for the period Sept. 1, 2015, through June 30, 2019, which will determine whether all fuel costs incurred are eligible for recovery. No procedural schedule has yet been established for this matter.
PCRF	Allows recovery of purchased power costs not included in Texas rates.
RPS	Recovers deferred costs for renewable energy programs in New Mexico.
TCRF	Recovers certain transmission infrastructure improvement costs and changes in wholesale transmission charges not included in Texas base rates.
Fixed Fuel and Purchased Recovery Factor	Provides for the over- or under-recovery of energy expenses. Regulations require refunding or surcharging over- or under- recovery amounts, including interest, when they exceed 4% of the utility's annual fuel and purchased energy costs on a rolling 12-month basis, if this condition is expected to continue.
Wholesale Fuel and Purchased Energy Cost Adjustment	SPS recovers fuel and purchased energy costs from its wholesale customers through a monthly wholesale fuel and purchased energy cost adjustment clause accepted by the FERC. Wholesale customers also pay the jurisdictional allocation of production costs.

Pending and Recently Concluded Regulatory Proceedings

Mechanism	Utility Service	Amount Requested (in millions)	Filing Date	Approval	Additional Information
					SPS (NMPRC)
Rate Case	Electric	$51	July 2019	Pending	In July 2019, SPS filed an electric rate case with the NMPRC seeking an increase in retail electric base rates of approximately $51 million. The rate request is based on an ROE of 10.35%, an equity ratio of 54.77%, a rate base of approximately $1.3 billion and a historic test year with rate base additions through Aug. 31, 2019. In December 2019, SPS revised its base rate increase request to approximately $47 million, based on an ROE of 10.10% and updated information. The request also included an increase of $14.6 million for accelerated depreciation including the early retirement of the Tolk Coal Plant in 2032. On Jan. 13, 2020, SPS and various parties filed an uncontested comprehensive stipulation. The stipulation includes a base rate revenue increase of $31 million, based on an ROE of 9.45% and an equity ratio of 54.77%. The stipulation also includes an acceleration of depreciation on the Tolk Coal Plant to reflect early retirement in 2037, which results in a total increase in depreciation expense of $8 million. The Signatories will not oppose the full application of depreciation rates associated with the 2032 retirement date in SPS' next base rate case. SPS anticipates final rates will go into effect in the second or third quarter of 2020.

SPS — Texas Electric Rate Case

In August 2019, SPS filed an electric rate case with the PUCT seeking an increase in retail electric base rates of approximately $141 million. The filing requests an ROE of 10.35%, a 54.65% equity ratio, a rate base of approximately $2.6 billion and is built on a 12 month period that ended June 30, 2019. In September 2019, SPS filed an update to the electric rate case and revised its requested increase to approximately $137 million.

On Feb. 10, 2020, the Alliance of Xcel Municipalities (AXM), Texas Industrial Energy Consumers (TIEC), Office of Public Utility Counsel (OPUC) and Department of Energy (DOE) filed testimony along with several other parties.

On Feb. 18, 2020, the PUCT Staff filed testimony that included certain adjustments and various ring-fencing measures.

Proposed modifications to SPS' request:

(Millions of Dollars)	Staff	AXM	OPUC	TIEC	DOE
SPS Direct Testimony	$ 137	$ 137	$ 137	$ 137	$ 137
Recommended base rate adjustments:					
ROE	(22)	(24)	(15)	(21)	(24)
Capital structure	(7)	(10)	—	(7)	(3)
Tolk/Harrington O&M disallowance	—	(7)	—	—	—
Distribution and Transmission Capital Disallowances [(a)]	(7)	—	—	—	—
Depreciation expense	(8)	(15)	(8)	(20)	—
Excess ADIT unprotected plant	—	—	(7)	—	—
Income Tax Expense Differences	(12)	—	—	—	—
Other, net	(6)	(6)	(1)	(1)	—
Total Adjustments	(62)	(62)	(31)	(49)	(27)
Total proposed revenue change	$ 75	$ 75	$ 106	$ 88	$ 110

Recommended Position	Staff	AXM	OPUC (b)	TIEC	DOE
ROE	9.1%	9.0%	—%	9.2%	9.0%
Equity Ratio	51.00%	50.00%	—%	51.00%	53.00%

(a) Staff recommends exclusion of approximately $134 million in transmission, distribution, and general plant in service in this rate case resulting in an approximate $7 million decrease to the revenue requirement.

(b) OPUC did not provide a recommendation for an ROE or equity ratio. For illustrative purposes an ROE of 9.5% was used.

The next steps in the procedural schedule are expected to be as follows:

- Rebuttal testimony — March 11, 2020; and
- Public hearing begins — March 30, 2020

A PUCT decision and implementation of final rates is anticipated in the third quarter of 2020.

Resource Plan

In December 2018, the NMPRC issued a final order accepting SPS' IRP.

SPS is forecasting a surplus capacity of 382 MW in 2028, but a capacity deficit of approximately 2,896 MW in 2038. SPS' optimal resource plan for the planning period incorporates the addition of wind, simple cycle combustion turbine generation, combined cycle energy and entering PPAs. Various factors may impact this IRP, which could potentially require updates to the action plan and will be the subject of future IRPs, including:

- New and revised environmental regulations;
- Impacts of variability due to participation in the SPP;
- Customer expectations;
- Technological advances;
- Groundwater aquifer depletion at SPS's Tolk Station;
- Aging generation fleet;
- Load growth and gas price variability;
- Changes to tax credits and incentives; and
- Changes to renewable portfolio standard acquisitions.

SPS is required to file an IRP in New Mexico every three years and will file its next IRP in July 2021.

Texas State ROFR

In May 2019, the Governor signed into law Senate Bill 1938, which grants incumbent utilities a ROFR to build transmission infrastructure when it directly interconnects to the utility's existing facility. In June 2019, a complaint was filed in the United States District Court for the Western District of Texas claiming the new ROFR law to be unconstitutional. The Texas Attorney General has made a motion to dismiss the federal court complaint. A ruling on the dismissal motion is expected in the first quarter of 2020.

Purchased Power Arrangements and Transmission Service Providers

SPS expects to use electric generating stations, power purchases, DSM and new generation options to meet its system capacity requirements.

Purchased Power — SPS purchases power from other utilities and IPPs. Long-term purchased power contracts typically require periodic capacity and energy charges. SPS also makes short-term purchases to meet system load and energy requirements to replace owned generation, meet operating reserve obligations or obtain energy at a lower cost.

Purchased Transmission Services — SPS has contractual arrangements with SPP and regional transmission service providers to deliver power and energy to its native load customers.

Natural Gas

SPS does not provide retail natural gas service, but purchases and transports natural gas for its generation facilities and operates natural gas pipeline facilities connecting the generation facilities to interstate natural gas pipelines. SPS is subject to the jurisdiction of the FERC with respect to natural gas transactions in interstate commerce and the PHMSA and PUCT for pipeline safety compliance.

Critical Accounting Policies and Estimates

Preparation of the consolidated financial statements requires the application of accounting rules and guidance, as well as the use of estimates. Application of these policies involves judgments regarding future events, including the likelihood of success of particular projects, legal and regulatory challenges and anticipated recovery of costs. These judgments could materially impact the consolidated financial statements, based on varying assumptions. In addition, the financial and operating environment also may have a significant effect on the operation of the business and results reported.

Accounting policies and estimates that are most significant to Xcel Energy's results of operations, financial condition or cash flows, and require management's most difficult, subjective or complex judgments are outlined below. Each of these has a higher likelihood of resulting in materially different reported amounts under different conditions or using different assumptions. Each critical accounting policy has been reviewed and discussed with the Audit Committee of Xcel Energy Inc.'s Board of Directors on a quarterly basis.

Regulatory Accounting

Xcel Energy is subject to the accounting for Regulated Operations, which provides that rate-regulated entities report assets and liabilities consistent with the recovery of those incurred costs in rates, if it is probable that such rates will be charged and collected. Our rates are derived through the ratemaking process, which results in the recording of regulatory assets and liabilities based on the probability of future cash flows. Regulatory assets generally represent incurred or accrued costs that have been deferred because future recovery from customers is probable. Regulatory liabilities generally represent amounts that are expected to be refunded to customers in future rates or amounts collected in current rates for future costs. In other businesses or industries, regulatory assets and regulatory liabilities would generally be charged to net income or other comprehensive income.

Each reporting period we assess the probability of future recoveries and obligations associated with regulatory assets and liabilities. Factors such as the current regulatory environment, recently issued rate orders and historical precedents are considered. Decisions made by regulatory agencies can directly impact the amount and timing of cost recovery as well as the rate of return on invested capital, and may materially impact our results of operations, financial condition or cash flows.

As of Dec. 31, 2019 and 2018, Xcel Energy recorded regulatory assets of $3.4 billion and $3.8 billion, respectively, and regulatory liabilities of $5.5 billion and $5.6 billion, respectively. Each subsidiary is subject to regulation that varies from jurisdiction to jurisdiction. If future recovery of costs in any such jurisdiction is no longer probable, Xcel Energy would be required to charge these assets to current net income or other comprehensive income. In assessing the probability of recovery of recognized regulatory assets, Xcel Energy noted no current or anticipated proposals or changes in the regulatory environment that it expects will materially impact the probability of recovery of the assets.

See Note 4 to the consolidated financial statements for further information.

Income Tax Accruals

Judgment, uncertainty and estimates are a significant aspect of the income tax accrual process that accounts for the effects of current and deferred income taxes. Uncertainty associated with the application of tax statutes and regulations and outcomes of tax audits and appeals require that judgment and estimates be made in the accrual process and in the calculation of the ETR.

Changes in tax laws and rates may affect recorded deferred tax assets and liabilities and our future ETR. ETR calculations are revised every quarter based on best available year-end tax assumptions, adjusted in the following year after returns are filed. The tax accrual estimates are trued-up to the actual amounts claimed on the tax returns and further adjusted after examinations by taxing authorities, as needed.

In accordance with the interim period reporting guidance, income tax expense for the first three quarters in a year is based on the forecasted annual ETR. The forecasted ETR reflects a number of estimates, including forecasted annual income, permanent tax adjustments and tax credits.

Valuation allowances are applied to deferred tax assets if it is more likely than not that at least a portion may not be realized based on an evaluation of expected future taxable income. Accounting for income taxes also requires that only tax benefits that meet the more likely than not recognition threshold can be recognized or continue to be recognized. We may adjust our unrecognized tax benefits and interest accruals as disputes with the IRS and state tax authorities are resolved, and as new developments occur. These adjustments may increase or decrease earnings.

See Note 7 to the consolidated financial statements for further information.

Employee Benefits

We sponsor several noncontributory, defined benefit pension plans and other postretirement benefit plans that cover almost all employees and certain retirees. Projected benefit costs are based on historical information and actuarial calculations that include key assumptions (annual return level on pension and postretirement health care investment assets, discount rates, mortality rates and health care cost trend rates, etc.). In addition, the pension cost calculation uses a methodology to reduce the volatility of investment performance over time. Pension assumptions are continually reviewed.

At Dec. 31, 2019, Xcel Energy set the rate of return on assets used to measure pension costs at 6.87%, which is consistent with the rate set in 2018. The rate of return used to measure postretirement health care costs is 4.50% at Dec. 31, 2019, which represents a 80 basis point decrease from 2018. Xcel Energy's pension investment strategy is based on plan-specific investments that seek to minimize investment and interest rate risk as a plan's funded status increases over time. This strategy results in a greater percentage of interest rate sensitive securities being allocated to plans with a higher funded status and a greater percentage of growth assets being allocated to plans having a lower funded status ratios.

Xcel Energy set the discount rates used to value the pension obligations at 3.49% and postretirement health care obligations at 3.47% at Dec. 31, 2019. This represents a 82 basis point and 85 basis point decrease, respectively, from 2018. Xcel Energy uses a bond matching study as its primary basis for determining the discount rate used to value pension and postretirement health care obligations. The bond matching study utilizes a portfolio of high grade (Aa or higher) bonds that matches the expected cash flows of Xcel Energy's benefit plans in amount and duration.

The effective yield on this cash flow matched bond portfolio determines the discount rate for the individual plans. The bond matching study is validated for reasonableness against the Merrill Lynch Corporate 15+ Bond Index. In addition, Xcel Energy reviews general actuarial survey data to assess the reasonableness of the discount rate selected.

If Xcel Energy were to use alternative assumptions, a 1% change would result in the following impact on 2019 pension costs:

	Pension Costs	
(Millions of Dollars)	**+1%**	**-1%**
Rate of return	$ (16)	$ 18
Discount rate [(a)]	(5)	9

(a) These costs include the effects of regulation.

Mortality rates are developed from actual and projected plan experience for pension plan and postretirement benefits. Xcel Energy's actuary conducts an experience study periodically as part of the process to determine an estimate of mortality. Xcel Energy considers standard mortality tables, improvement factors and the plans actual experience when selecting a best estimate.

As of Dec. 31, 2019, the initial medical trend cost claim assumptions for Pre-65 was 6.0% and Post-65 was 5.1%. The ultimate trend assumption remained at 4.5% for both Pre-65 and Post-65 claims costs. Xcel Energy bases its medical trend assumption on the long-term cost inflation expected in the health care market, considering the levels projected and recommended by industry experts, as well as recent actual medical cost experienced by Xcel Energy's retiree medical plan.

A 1% change in the assumed health care cost trend rate would have the following effects on Xcel Energy:

	Accumulated Postretirement Benefit Obligation		Service and Interest Components	
(Millions of Dollars)	**+1%**	**-1%**	**+1%**	**-1%**
Health care cost trend	$51	$(43)	$2	$(2)

Funding requirements in 2020 were $150 million and are expected to decline in the following years. Investment returns exceeded assumed levels in 2017 and 2019 and were below assumed levels in 2018.

The pension cost calculation uses a market-related valuation of pension assets. Xcel Energy uses a calculated value method to determine the market-related value of the plan assets. The market-related value is determined by adjusting the fair market value of assets at the beginning of the year to reflect the investment gains and losses (the difference between the actual investment return and the expected investment return on the market-related value) during each of the previous five years at the rate of 20% per year. As differences between actual and expected investment returns are incorporated into the market-related value, amounts are recognized in pension cost over the expected average remaining years of service for active employees (approximately 12 years in 2019).

Xcel Energy currently projects the pension costs recognized for financial reporting purposes will be $104 million in 2020 and $90 million in 2021, while the actual pension costs were $115 million in 2019 and $141 million in 2018. The expected decrease in 2020 and future year costs is primarily due to the reductions in loss amortizations.

Pension funding contributions across all four of Xcel Energy's pension plans, both voluntary and required, for 2017 - 2020:

- $150 million in January 2020;
- $154 million in 2019;
- $150 million in 2018; and
- $162 million in 2017.

Future amounts may change based on actual market performance, changes in interest rates and any changes in governmental regulations. Therefore, additional contributions could be required in the future.

Xcel Energy contributed $15 million, $11 million and $20 million during 2019, 2018 and 2017, respectively, to the postretirement health care plans. Xcel Energy expects to contribute approximately $10 million during 2020. Xcel Energy recovers employee benefits costs in its utility operations consistent with accounting guidance with the exception of the areas noted below.

- NSP-Minnesota recognizes pension expense in all regulatory jurisdictions using the aggregate normal cost actuarial method. Differences between aggregate normal cost and expense as calculated by pension accounting standards are deferred as a regulatory liability;
- In 2018, the PSCW approved NSP-Wisconsin's request for deferred accounting treatment of the 2018 pension settlement accounting expense;
- Regulatory Commissions in Colorado, Texas, New Mexico and FERC jurisdictions allow the recovery of other postretirement benefit costs only to the extent that recognized expense is matched by cash contributions to an irrevocable trust. Xcel Energy has consistently funded at a level to allow full recovery of costs in these jurisdictions;
- PSCo and SPS recognize pension expense in all regulatory jurisdictions based on expense consistent with accounting guidance. The Texas and Colorado electric retail jurisdictions and the Colorado gas retail jurisdiction, each record the difference between annual recognized pension expense and the annual amount of pension expense approved in their last respective general rate case as a deferral to a regulatory asset; and
- In 2018, PSCo was required to create a regulatory liability to adjust postretirement health care costs to zero in order to match the amounts collected in rates in the Colorado Gas retail jurisdiction.

See Note 11 to the consolidated financial statements for further information.

Nuclear Decommissioning

Xcel Energy recognizes liabilities for the expected cost of retiring tangible long-lived assets for which a legal obligation exists. These AROs are recognized at fair value as incurred and are capitalized as part of the cost of the related long-lived assets. In the absence of quoted market prices, Xcel Energy estimates the fair value of its AROs using present value techniques, in which it makes assumptions including estimates of the amounts and timing of future cash flows associated with retirement activities, credit-adjusted risk free rates and cost escalation rates. When the Company revises any assumptions, it adjusts the carrying amount of both the ARO liability and related long-lived asset. ARO liabilities are accreted to reflect the passage of time using the interest method.

A significant portion of Xcel Energy's AROs relates to the future decommissioning of NSP-Minnesota's nuclear facilities. The nuclear decommissioning obligation is funded by the external decommissioning trust fund. Difference between regulatory funding (including depreciation expense less returns from the external trust fund) and expense recognized is deferred as a regulatory asset. The amounts recorded for AROs related to future nuclear decommissioning were $2.1 billion in 2019 and $2.0 billion in 2018.

NSP-Minnesota obtains periodic independent cost studies in order to estimate the cost and timing of planned nuclear decommissioning activities. Estimates of future cash flows are highly uncertain and may vary significantly from actual results. NSP-Minnesota is required to file a nuclear decommissioning filing every three years. The filing covers all expenses for the decommissioning of the nuclear plants, including decontamination and removal of radioactive material.

The most recent triennial filing was approved by the MPUC in January 2019. This approval did not result in a change to the ARO liability. In December 2019, the MPUC ordered Xcel Energy to maintain the current accrual through 2020 to align with the approved one year stay out of the previously filed three-year electric rate case. Xcel Energy will evaluate the scenarios and potentially propose a new accrual starting in 2022 when it submits the next triennial filing in December 2020.

The following assumptions have a significant effect on the estimated nuclear obligation:

Timing — Decommissioning cost estimates are impacted by each facility's retirement date and timing of the actual decommissioning activities. Estimated retirement dates coincide with the expiration of each unit's operating license with the NRC (i.e., 2030 for Monticello and 2033 and 2034 for PI's Unit 1 and 2, respectively). The estimated timing of the decommissioning activities is based upon the DECON method, which assumes prompt removal and dismantlement. The use of the DECON method is required by the MPUC. Decommissioning activities are expected to begin at the end of the license date and be completed for both facilities by 2091.

Technology and Regulation — There is limited experience with actual decommissioning of large nuclear facilities. Changes in technology, experience and regulations could cause cost estimates to change significantly.

Escalation Rates — Escalation rates represent projected cost increases due to general inflation and increases in the cost of decommissioning activities. NSP-Minnesota used an escalation rate of 3.4% in calculating the ARO for nuclear decommissioning of its nuclear facilities, based on the weighted averages of labor and non-labor escalation factors calculated by Goldman Sachs Asset Management.

Discount Rates — Changes in timing or estimated cash flows that result in upward revisions to the ARO are calculated using the then-current credit-adjusted risk-free interest rate. The credit-adjusted risk-free rate in effect when the change occurs is used to discount the revised estimate of the incremental expected cash flows of the retirement activity.

If the change in timing or estimated expected cash flows results in a downward revision of the ARO, the undiscounted revised estimate of expected cash flows is discounted using the credit-adjusted risk-free rate in effect at the date of initial measurement and recognition of the original ARO. Discount rates ranging from approximately 4% to 7% have been used to calculate the net present value of the expected future cash flows over time.

Significant uncertainties exist in estimating future costs including the method to be utilized, ultimate costs to decommission and planned method of disposing spent fuel. If different cost estimates, life assumptions or cost escalation rates were utilized, the AROs could change materially.

However, changes in estimates have minimal impact on results of operations as NSP-Minnesota expects to continue to recover all costs in future rates.

The Company continually makes judgments and estimates related to these critical accounting policy areas, based on an evaluation of the assumptions and uncertainties for each area. The information and assumptions of these judgments and estimates will be affected by events beyond the control of Xcel Energy, or otherwise change over time. This may require adjustments to recorded results to better reflect updated information that becomes available. The accompanying financial statements reflect management's best estimates and judgments of the impact of these factors as of Dec. 31, 2019.

See Note 12 to the consolidated financial statements for further information.

Derivatives, Risk Management and Market Risk

We are exposed to a variety of market risks in the normal course of business. Market risk is the potential loss that may occur as a result of adverse changes in the market or fair value of a particular instrument or commodity. All financial and commodity-related instruments, including derivatives, are subject to market risk.

Xcel Energy is also exposed to the impact of adverse changes in price for energy and energy-related products, which is partially mitigated by the use of commodity derivatives. In addition to ongoing monitoring and maintaining credit policies intended to minimize overall credit risk, management takes steps to mitigate changes in credit and concentration risks associated with its derivatives and other contracts, including parental guarantees and requests of collateral. While we expect that the counterparties will perform under the contracts underlying its derivatives, the contracts expose us to certain credit and non-performance risk.

Distress in the financial markets may impact counterparty risk, the fair value of the securities in the nuclear decommissioning fund and pension fund and Xcel Energy's ability to earn a return on short-term investments.

Commodity Price Risk — We are exposed to commodity price risk in their electric and natural gas operations. Commodity price risk is managed by entering into long- and short-term physical purchase and sales contracts for electric capacity, energy and energy-related products and fuels used in generation and distribution activities. Commodity price risk is also managed through the use of financial derivative instruments. Our risk management policy allows it to manage commodity price risk within each rate-regulated operation per commission approved hedge plans.

Wholesale and Commodity Trading Risk — Xcel Energy conducts various wholesale and commodity trading activities, including the purchase and sale of electric capacity, energy, energy-related instruments and natural gas-related instruments, including derivatives. Our risk management policy allows management to conduct these activities within guidelines and limitations as approved by its risk management committee.

Fair value of net commodity trading contracts as of Dec. 31, 2019:

	Futures / Forwards Maturity				
(Millions of Dollars)	Less Than 1 Year	1 to 3 Years	4 to 5 Years	Greater Than 5 Years	Total Fair Value
NSP-Minnesota [(a)]	$ (1)	$ 2	$ 2	$ 3	$ 6
NSP-Minnesota [(b)]	2	(3)	(2)	(10)	(13)
PSCo [(b)]	(4)	(22)	(31)	—	(57)
	$ (3)	$ (23)	$ (31)	$ (7)	$ (64)

(a) Prices actively quoted or based on actively quoted prices.

(b) Prices based on models and other valuation methods.

	Options Maturity				
(Millions of Dollars)	Less Than 1 Year	1 to 3 Years	4 to 5 Years	Greater Than 5 Years	Total Fair Value
NSP-Minnesota [(a)]	$ 4	$ 1	$ —	$ —	$ 5

(a) Prices based on models and other valuation methods.

Changes in the fair value of commodity trading contracts before the impacts of margin-sharing for the years ended Dec. 31:

(Millions of Dollars)	2019	2018
Fair value of commodity trading net contract assets outstanding at Jan. 1	$ 17	$ 16
Contracts realized or settled during the period	(22)	(10)
Commodity trading contract additions and changes during the period	(54)	11
Fair value of commodity trading net contract assets outstanding at Dec. 31	$ (59)	$ 17

At Dec. 31, 2019, a 10% increase in market prices for commodity trading contracts would increase pretax income by approximately $10 million, whereas a 10% decrease would decrease pretax income by approximately $10 million. At Dec. 31, 2018, a 10% increase in market prices for commodity trading contracts would increase pretax income by approximately $16 million, whereas a 10% decrease would decrease pretax income by approximately $16 million.

The utility subsidiaries' commodity trading operations measure the outstanding risk exposure to price changes on contracts and obligations that have been entered into, but not closed, using an industry standard methodology known as VaR. VaR expresses the potential change in fair value on the outstanding contracts and obligations over a particular period of time under normal market conditions.

The VaRs for the NSP-Minnesota and PSCo commodity trading operations, excluding both non-derivative transactions and derivative transactions designated as normal purchase, normal sales, calculated on a consolidated basis using a Monte Carlo simulation with a 95% confidence level and a one-day holding period, were as follows:

(Millions of Dollars)	Year Ended Dec. 31	VaR Limit	Average	High	Low
2019	$ 0.4	$ 3.0	$ 0.6	$ 0.8	$ 0.3
2018	4.8	6.0	0.6	5.6	0.1

In November 2018, management temporarily increased the VaR limit to accommodate a 10-year transaction. NSP-Minnesota systematically hedging the transaction and the consolidated VaR returned below $3 million in early January 2019.

Nuclear Fuel Supply — NSP-Minnesota has received all enriched nuclear material for 2019 and has contracted for approximately 51% of its 2020 enriched nuclear material requirements from sources that could be impacted by sanctions against entities doing business with Iran. Those sanctions may impact the supply of enriched nuclear material supplied from Russia. Long-term, through 2030, NSP-Minnesota is scheduled to take delivery of approximately 29% of its average enriched nuclear material requirements from these sources. Alternate potential sources provide the flexibility to manage NSP-Minnesota's nuclear fuel supply. NSP-Minnesota periodically assesses if further actions are required to assure a secure supply of enriched nuclear material.

Interest Rate Risk — Xcel Energy is subject to interest rate risk. Our risk management policy allows interest rate risk to be managed through the use of fixed rate debt, floating rate debt and interest rate derivatives such as swaps, caps, collars and put or call options.

A 100 basis point change in the benchmark rate on Xcel Energy's variable rate debt would impact annual pretax interest expense by approximately $6 million in 2019 and $10 million in 2018.

NSP-Minnesota maintains a nuclear decommissioning fund, as required by the NRC. The nuclear decommissioning fund is subject to interest rate risk and equity price risk. The fund is invested in a diversified portfolio of cash equivalents, debt securities, equity securities and other investments. These investments may be used only for the purpose of decommissioning NSP-Minnesota's nuclear generating plants.

Realized and unrealized gains on the decommissioning fund investments are deferred as an offset of NSP-Minnesota's regulatory asset for nuclear decommissioning costs. Fluctuations in equity prices or interest rates affecting the nuclear decommissioning fund do not have a direct impact on earnings due to the application of regulatory accounting.

Changes in discount rates and expected return on plan assets impact the value of pension and postretirement plan assets and/or benefit costs.

Credit Risk — Xcel Energy is also exposed to credit risk. Credit risk relates to the risk of loss resulting from counterparties' nonperformance on their contractual obligations. The Company maintains credit policies intended to minimize overall credit risk and actively monitor these policies to reflect changes and scope of operations.

At Dec. 31, 2019, a 10% increase in commodity prices would have resulted in an increase in credit exposure of $19 million, while a decrease in prices of 10% would have resulted in an increase in credit exposure of $14 million. At Dec. 31, 2018, a 10% increase in commodity prices would have resulted in an increase in credit exposure of $14 million, while a decrease in prices of 10% would have resulted in an increase in credit exposure of $3 million.

Xcel Energy conducts credit reviews for all counterparties and employs credit risk controls, such as letters of credit, parental guarantees, master netting agreements and termination provisions. Credit exposure is monitored, and when necessary, the activity with a specific counterparty is limited until credit enhancement is provided. Distress in the financial markets could increase our credit risk.

Fair Value Measurements

Xcel Energy uses derivative contracts such as futures, forwards, interest rate swaps, options and FTRs to manage commodity price and interest rate risk. Derivative contracts, with the exception of those designated as normal purchase-normal sale contracts, are reported at fair value. The Company's investments held in the nuclear decommissioning fund, rabbi trusts, pension and other postretirement funds are also subject to fair value accounting.

Commodity Derivatives — Xcel Energy monitors the creditworthiness of the counterparties to its commodity derivative contracts and assesses each counterparty's ability to perform on the transactions. The impact of discounting commodity derivative assets for counterparty credit risk was not material to the fair value of commodity derivative assets at Dec. 31, 2019.

Adjustments to fair value for credit risk of commodity trading instruments are recorded in electric revenues. Credit risk adjustments for other commodity derivative instruments are recorded as other comprehensive income or deferred as regulatory assets and liabilities. Classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms. The impact of discounting commodity derivative liabilities for credit risk was immaterial at Dec. 31, 2019.

See Notes 10 and 11 to the consolidated financial statements for further information.

Liquidity and Capital Resources

Cash Flows

(Millions of Dollars)	2019	2018	2017
Net cash provided by operating activities	$ 3,263	$ 3,122	$ 3,126

Net cash provided by operating activities increased by $141 million for 2019 as compared to 2018. Increase was primarily due to additional net income (excluding amounts related to non-cash operating activities (e.g., depreciation and amortization and deferred tax expenses)), partially offset by increased refunds associated with TCJA.

Net cash provided by operating activities decreased by $4 million for 2018 as compared to 2017. Change was primarily due to refunds associated with the TCJA and timing of certain electric and natural gas recovery mechanisms, partially offset by the change in net income.

(Millions of Dollars)	2019	2018	2017
Net cash used in investing activities	$ (4,343)	$ (3,986)	$ (3,296)

Net cash used in investing activities increased by $357 million for 2019 as compared to 2018. Increase was primarily attributable to additional capital expenditures, primarily for wind projects.

Net cash used in investing activities increased by $690 million for 2018 as compared to 2017. Increase was largely related to higher capital expenditures for the Rush Creek, Foxtail and Hale wind generation facilities.

(Millions of Dollars)	2019	2018	2017
Net cash provided by financing activities	$ 1,181	$ 928	$ 168

Net cash provided by financing activities increased by $253 million for 2019 as compared to 2018. Increase was primarily attributable to higher proceeds from issuances of long-term debt and common stock (primarily due to the forward equity agreement settling in August 2019), partially offset by higher repayments of long-term debt and dividends paid.

Net cash provided by financing activities increased by $760 million for 2018 as compared to 2017. Increase was primarily due to lower repayments of long-term debt, proceeds from the issuances of common stock and additional debt financings, partially offset by lower short-term debt proceeds as compared to 2017.

Capital Requirements

Xcel Energy expects to meet future financing requirements by periodically issuing short-term debt, long-term debt, common stock, hybrid and other securities to maintain desired capitalization ratios.

Contractual Obligations and Other Commitments — Xcel Energy has contractual obligations and other commitments that will need to be funded in the future.

Contractual obligations and other commercial commitments as of Dec. 31, 2019:

		Payments Due by Period			
(Millions of Dollars)	**Total**	**Less than 1 Year**	**1 to 3 Years**	**3 to 5 Years**	**After 5 Years**
Long-term debt, principal and interest payments	$ 31,433	$ 1,422	$ 2,702	$ 2,514	$ 24,795
Finance lease obligations	271	14	26	24	207
Operating leases obligations [(a)]	2,116	262	520	469	865
Unconditional purchase obligations [(b)]	5,831	1,302	1,940	1,178	1,411
Other long-term obligations, including current portion	680	64	89	59	468
Other short-term obligations	442	442	—	—	—
Short-term debt	595	595	—	—	—
Total contractual cash obligations	$ 41,368	$ 4,101	$ 5,277	$ 4,244	$ 27,746

(a) Included in operating lease obligations are $236 million, $463 million, $422 million and $750 million, for the less than 1 year, 1 - 3 years, 3 - 5 years and after 5 years categories, respectively, pertaining to PPAs that were accounted for as operating leases.

(b) Xcel Energy Inc. and its subsidiaries have contracts providing for the purchase and delivery of a significant portion of its fuel (nuclear, natural gas and coal) requirements. Additionally, the utility subsidiaries of Xcel Energy Inc. have entered into non-lease purchase power agreements. Certain contractual purchase obligations are adjusted on indices. Effects of price changes are mitigated through cost of energy adjustment mechanisms.

Capital Expenditures — Current estimated base capital expenditures:

	Capital Forecast					
(Millions of Dollars)	**2020**	**2021**	**2022**	**2023**	**2024**	**2020 - 2024 Total**
By Subsidiary						
NSP-Minnesota	$ 2,025	$ 1,580	$ 1,670	$ 1,800	$ 1,845	$ 8,920
PSCo	1,415	1,445	1,720	1,565	1,530	7,675
SPS	1,025	530	700	750	800	3,805
NSP-Wisconsin	250	320	345	350	425	1,690
Other [(a)]	(85)	(65)	10	10	10	(120)
Total capital expenditures	$ 4,630	$ 3,810	$ 4,445	$ 4,475	$ 4,610	$ 21,970

(a) Other category includes intercompany transfers for safe harbor wind turbines. The $650M non-regulated acquisition of MEC in 2020 is not included above.

	Capital Forecast					
(Millions of Dollars)	**2020**	**2021**	**2022**	**2023**	**2024**	**2020 - 2024 Total**
By Function						
Renewables	$ 1,760	$ 315	$ —	$ —	$ —	$ 2,075
Electric generation	480	595	580	780	1,000	3,435
Electric transmission	625	835	1,295	1,270	1,260	5,285
Electric distribution	885	1,140	1,415	1,470	1,350	6,260
Natural gas	520	450	600	560	640	2,770
Other	360	475	555	395	360	2,145
Total capital expenditures	$ 4,630	$ 3,810	$ 4,445	$ 4,475	$ 4,610	$ 21,970

Xcel Energy's capital expenditure program is subject to continuous review and modification. Actual capital expenditures may vary from estimates due to changes in electric and natural gas projected load growth, regulatory decisions, legislative initiatives, reserve margin requirements, availability of purchased power, alternative plans for meeting long-term energy needs, compliance with environmental requirements, RPS and mergers, acquisition and divestiture opportunities.

The Company issues debt and equity securities to refinance retiring maturities, reduce short-term debt, fund capital programs, infuse equity in subsidiaries, fund asset acquisitions and for other general corporate purposes.

Financing Capital Expenditures through 2024 — Xcel Energy issues debt and equity securities to refinance retiring maturities, reduce short-term debt, fund capital programs, infuse equity in subsidiaries, fund asset acquisitions and for other general corporate purposes.

Current estimated financing plans for 2020 - 2024:

(Millions of Dollars)		
Funding Capital Expenditures		
Cash from operations [(a)]	$	13,905
New debt [(b)]		6,665
Equity through the DRIP and benefit program		400
Equity through the at-the-market program		250
Equity through forward equity agreements [(c)]		750
Base capital expenditures 2020 - 2024	$	21,970
Maturing Debt	$	3,245

(a) Net of dividends and pension funding.

(b) Reflects a combination of short and long-term debt; net of refinancing.

(c) Equity forward issued in 2019, but has not yet settled; settlement expected by Dec. 31, 2020

Common Stock Dividends — Future dividend levels will be dependent on Xcel Energy's results of operations, financial condition, cash flows, reinvestment opportunities and other factors, and will be evaluated by the Xcel Energy Inc. Board of Directors. In February 2020, Xcel Energy announced a quarterly dividend of $0.43 per share, which represents an increase of 6.2%.

Xcel Energy's dividend policy balances the following:

- Projected cash generation;
- Projected capital investment;
- A reasonable rate of return on shareholder investment; and
- The impact on Xcel Energy's capital structure and credit ratings.

In addition, there are certain statutory limitations that could affect dividend levels. Federal law places limits on the ability of public utilities within a holding company system to declare dividends. Specifically, under the Federal Power Act, a public utility may not pay dividends from any funds properly included in a capital account. The utility subsidiaries' dividends may be limited directly or indirectly by state regulatory commissions or bond indenture covenants.

See Note 5 to the consolidated financial statements for further information.

Pension Fund — Xcel Energy's pension assets are invested in a diversified portfolio of domestic and international equity securities, short-term to long-duration fixed income securities and alternative investments, including private equity, real estate and hedge funds.

Funded status and pension assumptions:

(Millions of Dollars)		Dec. 31, 2019		Dec. 31, 2018
Fair value of pension assets	$	3,184	$	2,742
Projected pension obligation [(a)]		3,701		3,477
Funded status	$	(517)	$	(735)

(a) Excludes non-qualified plan of $39 million and $33 million at Dec. 31, 2019 and 2018, respectively.

Pension Assumptions	2019	2018
Discount rate	3.49%	4.31%
Expected long-term rate of return	6.87	6.87

Capital Sources

Short-Term Funding Sources — Xcel Energy uses a number of sources to fulfill short-term funding needs, including operating cash flow, notes payable, commercial paper and bank lines of credit. The amount and timing of short-term funding needs depend on financing needs for construction expenditures, working capital and dividend payments.

Short-Term Investments — Xcel Energy Inc., NSP-Minnesota, NSP-Wisconsin, PSCo and SPS maintain cash operating and short-term investment accounts.

Short-Term Debt — Xcel Energy Inc., NSP-Minnesota, NSP-Wisconsin, PSCo and SPS each have individual commercial paper programs. Authorized levels for these commercial paper programs are:

- $1.25 billion for Xcel Energy Inc.;
- $700 million for PSCo;
- $500 million for NSP-Minnesota;
- $500 million for SPS; and
- $150 million for NSP-Wisconsin.

In addition, Xcel Energy Inc. borrowed $500 million under a 364-day term loan agreement that expires Dec. 1, 2020. Xcel Energy has an option to request an extension through Nov. 30, 2021.

Xcel Energy's outstanding short-term debt:

(Amounts in Millions, Except Interest Rates)		Three Months Ended Dec. 31, 2019
Borrowing limit	$	3,600
Amount outstanding at period end		595
Average amount outstanding		663
Maximum amount outstanding		945
Weighted average interest rate, computed on a daily basis		2.40%
Weighted average interest rate at end of period		2.34

(Amounts in Millions, Except Interest Rates)		Year Ended Dec. 31, 2019		Year Ended Dec. 31, 2018		Year Ended Dec. 31, 2017
Borrowing limit	$	3,600	$	3,250	$	3,250
Amount outstanding at period end		595		1,038		814
Average amount outstanding		1,115		788		644
Maximum amount outstanding		1,780		1,349		1,247
Weighted average interest rate, computed on a daily basis		2.72%		2.34%		1.35%
Weighted average interest rate at end of period		2.34		2.97		1.90

Credit Facility Agreements — Xcel Energy Inc., NSP-Minnesota, PSCo and SPS each have the right to request an extension of the revolving credit facility for two additional one-year periods beyond the June 2024 termination date. NSP-Wisconsin has the right to request an extension of the revolving credit facility termination date for an additional one-year period. All extension requests are subject to majority bank group approval.

As of Feb. 18, 2020, Xcel Energy Inc. and its utility subsidiaries had the following committed credit facilities available to meet liquidity needs:

(Millions of Dollars)	Facility	Drawn [(a)]	Available	Cash	Liquidity
Xcel Energy Inc.	$ 1,250	$ 759	$ 491	$ —	$ 491
PSCo	700	49	651	1	652
NSP-Minnesota	500	10	490	1	491
SPS	500	123	377	1	378
NSP-Wisconsin	150	62	88	—	88
Total	$ 3,100	$ 1,003	$ 2,097	$ 3	$ 2,100

(a) Includes outstanding commercial paper, term loan borrowings and letters of credit.

Registration Statements — Xcel Energy Inc.'s Articles of Incorporation authorize the issuance of one billion shares of $2.50 par value common stock. As of Dec. 31, 2019 and 2018, the Company had approximately 525 million shares and 514 million shares of common stock outstanding, respectively.

Xcel Energy Inc. and its utility subsidiaries have registration statements on file with the SEC pursuant to which they may sell securities from time to time. These registration statements, which are uncapped, permit Xcel Energy Inc. and its utility subsidiaries to issue debt and other securities in the future at amounts, prices and with terms to be determined at the time of future offerings, and in the case of our utility subsidiaries, subject to commission approval.

Planned Financing Activity — Xcel Energy's 2020 financing plans reflect the following:

- Xcel Energy Inc. — approximately $700 million of senior unsecured bonds and approximately $75 to $80 million of equity through the DRIP and benefit programs;
- NSP-Minnesota — approximately $550 million of first mortgage bonds;
- NSP-Wisconsin — approximately $100 million of first mortgage bonds
- PSCo — approximately $750 million of first mortgage bonds; and
- SPS — approximately $300 million of first mortgage bonds.

Forward Equity Agreements — In November 2018, Xcel Energy Inc. entered into forward equity agreements in connection with a completed $459 million public offering of 9.4 million shares of common stock. In August 2019, we settled the forward equity agreements by physically delivering 9.4 million shares of common equity for cash proceeds of $453 million.

In November 2019, Xcel Energy Inc. entered into forward equity agreements for a $743 million public offering of 11.8 million shares of common stock.

Other Equity — Xcel Energy also plans to issue approximately $75 to $80 million of equity annually through the DRIP and benefit programs during the five-year forecast time period.

Long-Term Borrowings and Other Financing Instruments — See Note 5 to the consolidated financial statements for further information.

Earnings Guidance

2020 GAAP and ongoing earnings guidance is a range of $2.73 to $2.83 per share.[(a)]

Key assumptions:

- Constructive outcomes in all rate case and regulatory proceedings.
- Normal weather patterns.
- Weather-normalized retail electric sales are projected to increase ~1%, including impact of leap year.
- Weather-normalized retail firm natural gas sales are projected to increase ~1%, including impact of leap year.
- Capital rider revenue is projected to increase $45 million to $55 million (net of PTCs). PTCs are credited to customers, through capital riders and reductions to electric margin.
- O&M expenses are projected to increase approximately 1% to 2%.
- Depreciation expense is projected to increase approximately $160 million to $170 million.
- Property taxes are projected to increase approximately $35 million to $45 million.
- Interest expense (net of AFUDC — debt) is projected to increase $50 million to $60 million.
- AFUDC — equity is projected to increase approximately $10 million to $20 million.
- The ETR is projected to be approximately 0%. The ETR reflects benefits of PTCs which are credited to customers through electric margin and will not impact net income.

(a) Ongoing earnings is calculated using net income and adjusting for certain nonrecurring or infrequent items that are, in management's view, not reflective of ongoing operations. Ongoing earnings could differ from those prepared in accordance with GAAP for unplanned and/or unknown adjustments. Xcel Energy is unable to forecast if any of these items will occur or provide a quantitative reconciliation of the guidance for ongoing EPS to corresponding GAAP EPS.

Off-Balance Sheet Arrangements

Xcel Energy does not have any off-balance-sheet arrangements, other than those currently disclosed, that have or are reasonably likely to have a current or future effect on financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that is material to investors.

ITEM 7A — QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See Item 7, incorporated by reference.

ITEM 8 — FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

See Item 15-1 for an index of financial statements included herein.

See Note 15 to the consolidated financial statements for further information.

Management Report on Internal Control Over Financial Reporting

The management of Xcel Energy Inc. is responsible for establishing and maintaining adequate internal control over financial reporting. Xcel Energy Inc.'s internal control system was designed to provide reasonable assurance to Xcel Energy Inc.'s management and board of directors regarding the preparation and fair presentation of published financial statements.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

Xcel Energy Inc. management assessed the effectiveness of Xcel Energy Inc.'s internal control over financial reporting as of Dec. 31, 2019. In making this assessment, it used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control — Integrated Framework (2013). Based on our assessment, we believe that, as of Dec. 31, 2019, Xcel Energy Inc.'s internal control over financial reporting is effective at the reasonable assurance level based on those criteria.

Xcel Energy Inc.'s independent registered public accounting firm has issued an audit report on Xcel Energy Inc.'s internal control over financial reporting. Its report appears herein.

/s/ BEN FOWKE	/s/ ROBERT C. FRENZEL
Ben Fowke	Robert C. Frenzel
Chairman, President, Chief Executive Officer and Director	Executive Vice President, Chief Financial Officer
Feb. 21, 2020	Feb. 21, 2020

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the stockholders and the Board of Directors of Xcel Energy Inc.

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of Xcel Energy Inc. and subsidiaries (the "Company") as of December 31, 2019 and 2018, the related consolidated statements of income, comprehensive income, stockholders' equity, and cash flows, for each of the three years in the period ended December 31, 2019, and the related notes and the schedules listed in the Index at Item 15 (collectively referred to as the "financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2019, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2019, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by COSO.

Basis for Opinions

The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management Report on Internal Controls over Financial Reporting. Our responsibility is to express an opinion on these financial statements and an opinion on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the financial statements included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures to respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current-period audit of the financial statements that was communicated or required to be communicated to the audit committee and that (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Regulatory Assets and Liabilities - Impact of Rate Regulation on the Financial Statements - Refer to Notes 4 and 12 to the consolidated financial statements

Critical Audit Matter Description

The Company is subject to rate regulation by state utility regulatory agencies, which have jurisdiction with respect to the rates of electric and natural gas distribution companies in Minnesota, North Dakota, South Dakota, Wisconsin, Michigan, Colorado, New Mexico, and Texas. The Company is also subject to the jurisdiction of the Federal Energy Regulatory Commission for its wholesale electric operations, hydroelectric generation licensing, accounting practices, wholesale sales for resale, transmission of electricity in interstate commerce, compliance with North American Electric Reliability Corporation standards, asset transactions and mergers and natural gas transactions in interstate commerce, (collectively with state utility regulatory agencies, the “Commissions”). Management has determined it meets the requirements under accounting principles generally accepted in the United States of America to prepare its financial statements applying the specialized rules to account for the effects of cost-based rate regulation. Accounting for the economics of rate regulation affects multiple financial statement line items and disclosures, including property, plant and equipment, regulatory assets and liabilities, operating revenues and expenses, and income taxes.

The Company is subject to regulatory rate setting processes. Rates are determined and approved in regulatory proceedings based on an analysis of the Company’s costs to provide utility service and a return on, and recovery of, the Company’s investment in assets required to deliver services to customers. Accounting for the Company’s regulated operations provides that rate-regulated entities report assets and liabilities consistent with the recovery of those incurred costs in rates, if it is probable that such rates will be charged and collected. The Commissions’ regulation of rates is premised on the full recovery of incurred costs and a reasonable rate of return on invested capital. Decisions by the Commissions in the future will impact the accounting for regulated operations, including decisions about the amount of allowable costs and return on invested capital included in rates and any refunds that may be required. In the rate setting process, the Company’s rates result in the recording of regulatory assets and liabilities based on the probability of future cash flows. Regulatory assets generally represent incurred or accrued costs that have been deferred because future recovery from customers is probable. Regulatory liabilities generally represent amounts that are expected to be refunded to customers in future rates or amounts collected in current rates for future costs.

We identified the impact of rate regulation as a critical audit matter due to the significant judgments made by management to support its assertions about impacted account balances and disclosures and the high degree of subjectivity involved in assessing the impact of future regulatory orders on the financial statements. Management judgments include assessing the likelihood of (1) recovery in future rates of incurred costs, (2) a disallowance of part of the cost of recently completed plant, and 3) a refund due to customers. Given that management’s accounting judgements are based on assumptions about the outcome of future decisions by the Commissions, auditing these judgments required specialized knowledge of accounting for rate regulation and the rate setting process due to its inherent complexities.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the uncertainty of future decisions by the Commissions included the following, among others:

- We tested the effectiveness of management’s controls over the evaluation of the likelihood of (1) the recovery in future rates of costs deferred as regulatory assets, and (2) a refund or a future reduction in rates that should be reported as regulatory liabilities. We also tested the effectiveness of management’s controls over the recognition of regulatory assets or liabilities and the monitoring and evaluation of regulatory developments that may affect the likelihood of recovering costs in future rates or of a future reduction in rates.

- We evaluated the Company’s disclosures related to the impacts of rate regulation, including the balances recorded and regulatory developments.

- We read relevant regulatory orders issued by the Commissions for the Company, regulatory statutes, interpretations, procedural memorandums, filings made by intervenors, and other publicly available information to assess the likelihood of recovery in future rates or of a future reduction in rates based on precedence of the Commissions’ treatment of similar costs under similar circumstances. We also evaluated regulatory filings for any evidence that intervenors are challenging full recovery of the cost of any capital projects. If the full recovery of project costs is being challenged by intervenors, we evaluated management’s assessment of the probability of a disallowance. We evaluated the external information and compared to the Company’s recorded regulatory assets and liabilities for completeness.

- We obtained management’s analysis and correspondence from counsel, as appropriate, regarding regulatory assets or liabilities not yet addressed in a regulatory order to assess management’s assertion that amounts are probable of recovery or a future reduction in rates.

/s/ DELOITTE & TOUCHE LLP
Minneapolis, Minnesota
February 21, 2020

We have served as the Company’s auditor since 2002.

XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
(amounts in millions, except per share data)

	Year Ended Dec. 31		
	2019	2018	2017
Operating revenues			
Electric	$ 9,575	$ 9,719	$ 9,676
Natural gas	1,868	1,739	1,650
Other	86	79	78
Total operating revenues	11,529	11,537	11,404
Operating expenses			
Electric fuel and purchased power	3,510	3,854	3,757
Cost of natural gas sold and transported	918	843	823
Cost of sales — other	40	35	34
Operating and maintenance expenses	2,338	2,352	2,270
Conservation and demand side management program expenses	285	290	273
Depreciation and amortization	1,765	1,642	1,479
Taxes (other than income taxes)	569	556	545
Total operating expenses	9,425	9,572	9,181
Operating income	2,104	1,965	2,223
Other income (expense), net	16	(14)	(10)
Equity earnings of unconsolidated subsidiaries	39	35	30
Allowance for funds used during construction — equity	77	108	75
Interest charges and financing costs			
Interest charges — includes other financing costs of $26, $25 and $24, respectively	773	700	663
Allowance for funds used during construction — debt	(37)	(48)	(35)
Total interest charges and financing costs	736	652	628
Income before income taxes	1,500	1,442	1,690
Income taxes	128	181	542
Net income	$ 1,372	$ 1,261	$ 1,148
Weighted average common shares outstanding:			
Basic	519	511	509
Diluted	520	511	509
Earnings per average common share:			
Basic	$ 2.64	$ 2.47	$ 2.26
Diluted	2.64	2.47	2.25

See Notes to Consolidated Financial Statements

XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(amounts in millions)

	Year Ended Dec. 31		
	2019	2018	2017
Net income	$ 1,372	$ 1,261	$ 1,148
Other comprehensive (loss) income			
Defined pension and other postretirement benefits:			
Net pension and retiree medical loss arising during the period, net of tax of $0, $(2) and $(2), respectively	—	(6)	(3)
Reclassification of loss to net income, net of tax of $1, $3 and $5, respectively	3	9	7
Derivative instruments:			
Net fair value decrease, net of tax of $(8), $(2) and $0, respectively	(23)	(5)	—
Reclassification of loss to net income, net of tax of $1, $1 and $2, respectively	3	3	3
Total other comprehensive (loss) income	(17)	1	7
Total comprehensive income	$ 1,355	$ 1,262	$ 1,155

See Notes to Consolidated Financial Statements

XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(amounts in millions)

	Year Ended Dec. 31		
	2019	2018	2017
Operating activities			
Net income	$ 1,372	$ 1,261	$ 1,148
Adjustments to reconcile net income to cash provided by operating activities:			
Depreciation and amortization	1,785	1,659	1,495
Nuclear fuel amortization	119	122	114
Deferred income taxes	143	218	640
Allowance for equity funds used during construction	(77)	(108)	(75)
Equity earnings of unconsolidated subsidiaries	(39)	(35)	(30)
Dividends from unconsolidated subsidiaries	40	37	41
Provision for bad debts	42	42	39
Share-based compensation expense	58	45	57
Net realized and unrealized hedging and derivative transactions	45	22	2
Changes in operating assets and liabilities:			
Accounts receivable	(20)	(105)	(60)
Accrued unbilled revenues	42	9	(34)
Inventories	(84)	(65)	(3)
Other current assets	25	18	9
Accounts payable	(12)	90	43
Net regulatory assets and liabilities	(66)	223	(16)
Other current liabilities	(15)	(61)	(38)
Pension and other employee benefit obligations	(135)	(179)	(133)
Other, net	40	(71)	(73)
Net cash provided by operating activities	3,263	3,122	3,126
Investing activities			
Utility capital/construction expenditures	(4,225)	(3,957)	(3,244)
Purchases of investment securities	(995)	(853)	(1,697)
Proceeds from the sale of investment securities	975	833	1,669
Other, net	(98)	(9)	(24)
Net cash used in investing activities	(4,343)	(3,986)	(3,296)
Financing activities			
(Repayments of) proceeds from short-term borrowings, net	(443)	225	422
Proceeds from issuance of long-term debt	2,920	1,675	1,518
Repayments of long-term debt, including reacquisition premiums	(949)	(452)	(1,030)
Proceeds from issuance of common stock	458	230	—
Dividends paid	(791)	(730)	(721)
Other, net	(14)	(20)	(21)
Net cash provided by financing activities	1,181	928	168
Net change in cash, cash equivalents and restricted cash	101	64	(2)
Cash, cash equivalents and restricted cash at beginning of period	147	83	85
Cash, cash equivalents and restricted cash at end of period	$ 248	$ 147	$ 83
Supplemental disclosure of cash flow information:			
Cash paid for interest (net of amounts capitalized)	$ (698)	$ (633)	$ (616)
Cash received for income taxes, net	53	27	44
Supplemental disclosure of non-cash investing and financing transactions:			
Accrued property, plant and equipment additions	$ 421	$ 388	$ 464
Inventory and other asset transfers to property, plant and equipment	88	129	63
Operating lease right-of-use assets	1,843	—	—
Allowance for equity funds used during construction	77	108	75
Issuance of common stock for reinvested dividends and equity awards	63	67	31

See Notes to Consolidated Financial Statements

XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(amounts in millions, except share and per share)

	Dec. 31 2019	Dec. 31 2018
Assets		
Current assets		
Cash and cash equivalents	$ 248	$ 147
Accounts receivable, net	837	860
Accrued unbilled revenues	713	755
Inventories	544	548
Regulatory assets	488	464
Derivative instruments	55	87
Prepaid taxes	43	79
Prepayments and other	185	154
Total current assets	3,113	3,094
Property, plant and equipment, net	39,483	36,944
Other assets		
Nuclear decommissioning fund and other investments	2,731	2,317
Regulatory assets	2,935	3,326
Derivative instruments	22	34
Operating lease right-of-use assets	1,672	—
Other	492	272
Total other assets	7,852	5,949
Total assets	$ 50,448	$ 45,987
Liabilities and Equity		
Current liabilities		
Current portion of long-term debt	$ 702	$ 406
Short-term debt	595	1,038
Accounts payable	1,294	1,237
Regulatory liabilities	407	436
Taxes accrued	466	450
Accrued interest	192	174
Dividends payable	212	195
Derivative instruments	38	61
Other	662	463
Total current liabilities	4,568	4,460
Deferred credits and other liabilities		
Deferred income taxes	4,509	4,165
Deferred investment tax credits	49	54
Regulatory liabilities	5,077	5,187
Asset retirement obligations	2,701	2,568
Derivative instruments	175	129
Customer advances	203	199
Pension and employee benefit obligations	785	994
Operating lease liabilities	1,549	—
Other	186	206
Total deferred credits and other liabilities	15,234	13,502
Commitments and contingencies		
Capitalization		
Long-term debt	17,407	15,803
Common stock — 1,000,000,000 shares authorized of $2.50 par value; 524,539,000 and 514,036,787 shares outstanding at Dec. 31, 2019 and 2018, respectively	1,311	1,285
Additional paid in capital	6,656	6,168
Retained earnings	5,413	4,893
Accumulated other comprehensive loss	(141)	(124)
Total common stockholders' equity	13,239	12,222
Total liabilities and equity	$ 50,448	$ 45,987

See Notes to Consolidated Financial Statements

XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS' EQUITY
(amounts in millions, shares in thousands)

	Common Stock Issued					
	Shares	Par Value	Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Common Stockholders' Equity
Balance at Dec. 31, 2016	507,223	$ 1,268	$ 5,881	$ 3,982	$ (110)	$ 11,021
Net income				1,148		1,148
Other comprehensive loss					7	7
Dividends declared on common stock ($1.44 per share)				(736)		(736)
Issuances of common stock	611	1	4			5
Repurchases of common stock	(71)	—	(3)			(3)
Share-based compensation			16	(3)		13
Adoption of ASU No. 2018-02				22	(22)	—
Balance at Dec. 31, 2017	507,763	$ 1,269	$ 5,898	$ 4,413	$ (125)	$ 11,455
Net income				1,261		1,261
Other comprehensive income					1	1
Dividends declared on common stock ($1.52 per share)				(780)		(780)
Issuances of common stock	6,296	16	254			270
Repurchases of common stock	(22)	—	(1)			(1)
Share-based compensation			17	(1)		16
Balance at Dec. 31, 2018	514,037	$ 1,285	$ 6,168	$ 4,893	$ (124)	$ 12,222
Net income				1,372		1,372
Other comprehensive income					(17)	(17)
Dividends declared on common stock ($1.62 per share)				(846)		(846)
Issuances of common stock	10,508	26	468			494
Repurchases of common stock	(6)	—	—			—
Share-based compensation			20	(6)		14
Balance at Dec. 31, 2019	524,539	$ 1,311	$ 6,656	$ 5,413	$ (141)	$ 13,239

See Notes to Consolidated Financial Statements

XCEL ENERGY INC. AND SUBSIDIARIES
Notes to Consolidated Financial Statements

1. Summary of Significant Accounting Policies

General — Xcel Energy Inc.'s utility subsidiaries are engaged in the regulated generation, purchase, transmission, distribution and sale of electricity and in the regulated purchase, transportation, distribution and sale of natural gas.

Xcel Energy's regulated operations include the activities of NSP-Minnesota, NSP-Wisconsin, PSCo and SPS. These utility subsidiaries serve electric and natural gas customers in portions of Colorado, Michigan, Minnesota, New Mexico, North Dakota, South Dakota, Texas and Wisconsin. Also included in regulated operations are WGI, an interstate natural gas pipeline company, and WYCO, a joint venture with CIG to develop and lease natural gas pipeline, storage and compression facilities.

Xcel Energy Inc.'s nonregulated subsidiaries include Eloigne, Capital Services and the newly formed MEC Holdings LLC. Eloigne invests in rental housing projects that qualify for low-income housing tax credits. Capital Services procures equipment for construction of renewable generation facilities at other subsidiaries. Xcel Energy Inc. owns the following additional direct subsidiaries, some of which are intermediate holding companies with additional subsidiaries: Xcel Energy Wholesale Group Inc., Xcel Energy Markets Holdings Inc., Xcel Energy Ventures Inc., Xcel Energy Retail Holdings Inc., Xcel Energy Communications Group, Inc., Xcel Energy International Inc., Xcel Energy Transmission Holding Company, LLC, Nicollet Holdings Company, LLC, Nicollet Project Holdings LLC, Xcel Energy Venture Holdings Inc. and Xcel Energy Services Inc. Xcel Energy Inc. and its subsidiaries collectively are referred to as Xcel Energy.

Xcel Energy's consolidated financial statements include its wholly-owned subsidiaries and VIEs for which it is the primary beneficiary. All intercompany transactions and balances are eliminated, unless a different treatment is appropriate for rate regulated transactions.

Xcel Energy uses the equity method of accounting for its investment in WYCO. Xcel Energy's equity earnings in WYCO are included on the consolidated statements of income as equity earnings of unconsolidated subsidiaries.

Xcel Energy has investments in certain plants and transmission facilities jointly owned with nonaffiliated utilities. Xcel Energy's proportionate share of jointly owned facilities is recorded as property, plant and equipment on the consolidated balance sheets, and Xcel Energy's proportionate share of the operating costs associated with these facilities is included in its consolidated statements of income.

Xcel Energy's consolidated financial statements are presented in accordance with GAAP. All of the utility subsidiaries' underlying accounting records also conform to the FERC uniform system of accounts. Certain amounts in the 2018 and 2017 consolidated financial statements or notes have been reclassified to conform to the 2019 presentation for comparative purposes; however, such reclassifications did not affect net income, total assets, liabilities, equity or cash flows.

Xcel Energy has evaluated events occurring after Dec. 31, 2019 up to the date of issuance of these consolidated financial statements. These statements contain all necessary adjustments and disclosures resulting from that evaluation.

Use of Estimates — Xcel Energy uses estimates based on the best information available in recording transactions and balances resulting from business operations. Estimates are used on items such as plant depreciable lives or potential disallowances, AROs, certain regulatory assets and liabilities, tax provisions, uncollectible amounts, environmental costs, unbilled revenues, jurisdictional fuel and energy cost allocations and actuarially determined benefit costs. Recorded estimates are revised when better information becomes available or actual amounts can be determined. Revisions can affect operating results.

Regulatory Accounting — Xcel Energy Inc.'s regulated utility subsidiaries account for income and expense items in accordance with accounting guidance for regulated operations. Under this guidance:

- Certain costs, which would otherwise be charged to expense or other comprehensive income, are deferred as regulatory assets based on the expected ability to recover the costs in future rates; and
- Certain credits, which would otherwise be reflected as income or other comprehensive income, are deferred as regulatory liabilities based on the expectation the amounts will be returned to customers in future rates, or because the amounts were collected in rates prior to the costs being incurred.

Estimates of recovering deferred costs and returning deferred credits are based on specific ratemaking decisions or precedent for each item. Regulatory assets and liabilities are amortized consistent with the treatment in the rate setting process.

If changes in the regulatory environment occur, the utility subsidiaries may no longer be eligible to apply this accounting treatment and may be required to eliminate regulatory assets and liabilities from their balance sheets. Such changes could have a material effect on Xcel Energy's results of operations, financial condition and cash flows.

See Note 4 for further information.

Income Taxes — Xcel Energy accounts for income taxes using the asset and liability method, which requires recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the financial statements. Xcel Energy defers income taxes for all temporary differences between pretax financial and taxable income and between the book and tax bases of assets and liabilities. Xcel Energy uses rates that are scheduled to be in effect when the temporary differences are expected to reverse. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in the period that includes the enactment date.

The effects of tax rate changes that are attributable to the utility subsidiaries are generally subject to a normalization method of accounting. Therefore, the revaluation of most of the utility subsidiaries' net deferred taxes upon a tax rate reduction results in the establishment of a net regulatory liability, which will be refundable to utility customers over the remaining life of the related assets. A tax rate increase would result in the establishment of a similar regulatory asset.

Reversal of certain temporary differences are accounted for as current income tax expense due to the effects of past regulatory practices when deferred taxes were not required to be recorded due to the use of flow through accounting for ratemaking purposes. Tax credits are recorded when earned unless there is a requirement to defer the benefit and amortize it over the book depreciable lives of the related property. The requirement to defer and amortize tax credits only applies to federal ITCs related to public utility property. Utility rate regulation also has resulted in the recognition of regulatory assets and liabilities related to income taxes. Deferred tax assets are reduced by a valuation allowance if it is more likely than not that some portion or all of the deferred tax asset will not be realized.

Xcel Energy follows the applicable accounting guidance to measure and disclose uncertain tax positions that it has taken or expects to take in its income tax returns. Xcel Energy recognizes a tax position in its consolidated financial statements when it is more likely than not that the position will be sustained upon examination based on the technical merits of the position. Recognition of changes in uncertain tax positions are reflected as a component of income tax expense.

Xcel Energy reports interest and penalties related to income taxes within the other income and interest charges in the consolidated statements of income.

Xcel Energy Inc. and its subsidiaries file consolidated federal income tax returns as well as consolidated or separate state income tax returns. Federal income taxes paid by Xcel Energy Inc. are allocated to its subsidiaries based on separate company computations. A similar allocation is made for state income taxes paid by Xcel Energy Inc. in connection with consolidated state filings. Xcel Energy Inc. also allocates its own income tax benefits to its direct subsidiaries.

See Note 7 for further information.

Property, Plant and Equipment and Depreciation in Regulated Operations — Property, plant and equipment is stated at original cost. The cost of plant includes direct labor and materials, contracted work, overhead costs and AFUDC. The cost of plant retired is charged to accumulated depreciation and amortization. Amounts recovered in rates for future removal costs are recorded as regulatory liabilities. Significant additions or improvements extending asset lives are capitalized, while repairs and maintenance costs are charged to expense as incurred. Maintenance and replacement of items determined to be less than a unit of property are charged to operating expenses as incurred. Planned maintenance activities are charged to operating expense unless the cost represents the acquisition of an additional unit of property or the replacement of an existing unit of property.

Property, plant and equipment is tested for impairment when it is determined that the carrying value of the assets may not be recoverable. A loss is recognized in the current period if it becomes probable that part of a cost of a plant under construction or recently completed plant will be disallowed for recovery from customers and a reasonable estimate of the disallowance can be made. For investments in property, plant and equipment that are abandoned and not expected to go into service, incurred costs and related deferred tax amounts are compared to the discounted estimated future rate recovery, and a loss is recognized, if necessary.

Xcel Energy records depreciation expense using the straight-line method over the plant's useful life. Actuarial life studies are performed and submitted to the state and federal commissions for review. Upon acceptance by the various commissions, the resulting lives and net salvage rates are used to calculate depreciation. Depreciation expense, expressed as a percentage of average depreciable property, was approximately 3.3% for 2019, 3.1% for 2018 and 2017.

See Note 3 for further information.

AROs — Xcel Energy accounts for AROs under accounting guidance that requires a liability for the fair value of an ARO to be recognized in the period in which it is incurred if it can be reasonably estimated, with the offsetting associated asset retirement costs capitalized as a long-lived asset. The liability is generally increased over time by applying the effective interest method of accretion, and the capitalized costs are depreciated over the useful life of the long-lived asset. Changes resulting from revisions to the timing or amount of expected asset retirement cash flows are recognized as an increase or a decrease in the ARO. The utility subsidiaries also recover through rates certain future plant removal costs in addition to AROs.

The accumulated removal costs for these obligations are reflected in the consolidated balance sheets as a regulatory liability.

See Note 12 for further information.

Nuclear Decommissioning — Nuclear decommissioning studies that estimate NSP-Minnesota's costs of decommissioning its nuclear power plants are performed at least every three years and submitted to the state commissions for approval.

For ratemaking purposes, NSP-Minnesota recovers regulator-approved decommissioning costs of its nuclear power plants over each facility's expected service life, typically based on the triennial decommissioning studies. The studies consider estimated future costs of decommissioning and the market value of investments in trust funds and recommend annual funding amounts. Amounts collected in rates are deposited in the trust funds. For financial reporting purposes, NSP-Minnesota accounts for nuclear decommissioning as an ARO.

Restricted funds for the payment of future decommissioning expenditures for NSP-Minnesota's nuclear facilities are included in nuclear decommissioning fund and other assets on the consolidated balance sheets.

See Note 10 and 12 for further information.

Benefit Plans and Other Postretirement Benefits — Xcel Energy maintains pension and postretirement benefit plans for eligible employees. Recognizing the cost of providing benefits and measuring the projected benefit obligation of these plans requires management to make various assumptions and estimates.

Certain unrecognized actuarial gains and losses and unrecognized prior service costs or credits are deferred as regulatory assets and liabilities, rather than recorded as other comprehensive income, based on regulatory recovery mechanisms.

See Note 11 for further information.

Environmental Costs — Environmental costs are recorded when it is probable Xcel Energy is liable for remediation costs and the liability can be reasonably estimated. Costs are deferred as a regulatory asset if it is probable that the costs will be recovered from customers in future rates. Otherwise, the costs are expensed. If an environmental expense is related to facilities currently in use, such as emission-control equipment, the cost is capitalized and depreciated over the life of the plant.

Estimated remediation costs are regularly adjusted as estimates are revised and remediation proceeds. If other participating potentially responsible parties exist and acknowledge their potential involvement with a site, costs are estimated and recorded only for Xcel Energy's expected share of the cost.

Future costs of restoring sites are treated as a capitalized cost of plant retirement. The depreciation expense levels recoverable in rates include a provision for removal expenses. Removal costs recovered in rates before the related costs are incurred are classified as a regulatory liability.

See Note 12 for further information.

Revenue from Contracts with Customers — Performance obligations related to the sale of energy are satisfied as energy is delivered to customers. Xcel Energy recognizes revenue that corresponds to the price of the energy delivered to the customer. The measurement of energy sales to customers is generally based on the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated, and the corresponding unbilled revenue is recognized.

Xcel Energy does not recognize a separate financing component of its collections from customers as contract terms are short-term in nature. Xcel Energy presents its revenues net of any excise or sales taxes or fees. The utility subsidiaries recognize sales to customers on a gross basis in electric revenues and cost of sales. Revenues and charges for short term wholesale sales of excess energy transacted through RTOs are also recorded on a gross basis. Other RTO revenues and charges are recorded on a net basis in cost of sales.

See Note 6 for further information.

Cash and Cash Equivalents — Xcel Energy considers investments in instruments with a remaining maturity of three months or less at the time of purchase to be cash equivalents.

Accounts Receivable and Allowance for Bad Debts — Accounts receivable are stated at the actual billed amount net of an allowance for bad debts. Xcel Energy establishes an allowance for uncollectible receivables based on a policy that reflects its expected exposure to the credit risk of customers.

At both Dec. 31, 2019 and 2018, the allowance for bad debts was $55 million.

Inventory — Inventory is recorded at average cost and consisted of the following:

(Millions of Dollars)	Dec. 31, 2019	Dec. 31, 2018
Inventories		
Materials and supplies	$ 270	$ 271
Fuel	191	170
Natural gas	83	107
Total inventories	$ 544	$ 548

Fair Value Measurements — Xcel Energy presents cash equivalents, interest rate derivatives, commodity derivatives and nuclear decommissioning fund assets at estimated fair values in its consolidated financial statements.

Cash equivalents are recorded at cost plus accrued interest; money market funds are measured using quoted NAVs. For interest rate derivatives, quoted prices based primarily on observable market interest rate curves are used to establish fair value. For commodity derivatives, the most observable inputs available are generally used to determine the fair value of each contract. In the absence of a quoted price, Xcel Energy may use quoted prices for similar contracts or internally prepared valuation models to determine fair value.

For the pension and postretirement plan assets and nuclear decommissioning fund, published trading data and pricing models, generally using the most observable inputs available, are utilized to estimate fair value for each security.

See Notes 10 and 11 for further information.

Derivative Instruments — Xcel Energy uses derivative instruments in connection with its interest rate, utility commodity price, vehicle fuel price and commodity trading activities, including forward contracts, futures, swaps and options. Any derivative instruments not qualifying for the normal purchases and normal sales exception are recorded on the consolidated balance sheets at fair value as derivative instruments. Classification of changes in fair value for those derivative instruments is dependent on the designation of a qualifying hedging relationship. Changes in fair value of derivative instruments not designated in a qualifying hedging relationship are reflected in current earnings or as a regulatory asset or liability. Classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms.

Gains or losses on commodity trading transactions are recorded as a component of electric operating revenues; hedging transactions for vehicle fuel costs are recorded as a component of capital projects and O&M costs; and interest rate hedging transactions are recorded as a component of interest expense.

Normal Purchases and Normal Sales — Xcel Energy enters into contracts for purchases and sales of commodities for use in its operations. At inception, contracts are evaluated to determine whether a derivative exists and/or whether an instrument may be exempted from derivative accounting if designated as a normal purchase or normal sale.

See Note 10 for further information.

Commodity Trading Operations — All applicable gains and losses related to commodity trading activities are shown on a net basis in electric operating revenues in the consolidated statements of income.

Commodity trading activities are not associated with energy produced from Xcel Energy's generation assets or energy and capacity purchased to serve native load. Commodity trading contracts are recorded at fair market value and commodity trading results include the impact of all margin-sharing mechanisms.

See Note 10 for further information.

Other Utility Items

AFUDC — AFUDC represents the cost of capital used to finance utility construction activity. AFUDC is computed by applying a composite financing rate to qualified CWIP. The amount of AFUDC capitalized as a utility construction cost is credited to other nonoperating income (for equity capital) and interest charges (for debt capital). AFUDC amounts capitalized are included in Xcel Energy's rate base for establishing utility rates.

Alternative Revenue — Certain rate rider mechanisms (including decoupling and CIP/DSM programs) qualify as alternative revenue programs. These mechanisms arise from costs imposed upon the utility by action of a regulator or legislative body related to an environmental, public safety or other mandate. When certain criteria are met, including expected collection within 24 months, revenue is recognized equal to the revenue requirement, which may include incentives and return on rate base items. Billing amounts are revised periodically for differences between total amount collected and revenue earned, which may increase or decrease the level of revenue collected from customers. Alternative revenues arising from these programs are presented on a gross basis and disclosed separately from revenue from contracts with customers.

See Note 6 for further information.

Conservation Programs — Costs incurred for DSM and CIP programs are deferred if it is probable future revenue will recover the incurred cost. Revenues recognized for incentive programs for the recovery of lost margins and/or conservation performance incentives are limited to amounts expected to be collected within 24 months from the year they are earned. Regulatory assets are recognized to reflect the amount of costs or earned incentives that have not yet been collected from customers.

Emission Allowances — Emission allowances are recorded at cost, including broker commission fees. The inventory accounting model is utilized for all emission allowances and sales of these allowances are included in electric revenues.

Nuclear Refueling Outage Costs — Xcel Energy uses a deferral and amortization method for nuclear refueling costs. This method amortizes costs over the period between refueling outages consistent with rate recovery.

RECs — Cost of RECs that are utilized for compliance is recorded as electric fuel and purchased power expense. In certain jurisdictions, Xcel Energy reduces recoverable fuel costs for the cost of RECs and records that cost as a regulatory asset when the amount is recoverable in future rates.

Sales of RECs are recorded in electric revenues on a gross basis. The cost of these RECs and amounts credited to customers under margin-sharing mechanisms are recorded in electric fuel and purchased power expense.

Cost of RECs that are utilized to support commodity trading activities are recorded in a similar manner as the associated commodities and are shown on a net basis in electric operating revenues in the consolidated statements of income.

2. Accounting Pronouncements

Recently Issued

Credit Losses — In 2016, the FASB issued *Financial Instruments - Credit Losses, Topic 326 (ASC Topic 326),* which changes how entities account for losses on receivables and certain other assets. The guidance requires use of a current expected credit loss model, which may result in earlier recognition of credit losses than under previous accounting standards. ASC Topic 326 is effective for interim and annual periods beginning on or after Dec. 15, 2019 and will be applied using a modified-retrospective approach, with a cumulative-effect adjustment to retained earnings as of Jan. 1, 2020.

Xcel Energy expects the impact of adoption of the new standard to include first-time recognition of expected credit losses (i.e., bad debt expense) on unbilled revenues, with the initial allowance established at Jan. 1, 2020 charged to retained earnings. Recognition of this allowance and other impacts of adoption are expected to be immaterial to the consolidated financial statements.

Recently Adopted

Leases — In 2016, the FASB issued *Leases*, *Topic 842 (ASC Topic 842)*, which provides new accounting and disclosure guidance for leasing activities, most significantly requiring that operating leases be recognized on the balance sheet. Xcel Energy adopted the guidance on Jan. 1, 2019 utilizing the package of transition practical expedients provided by the new standard, including carrying forward prior conclusions on whether agreements existing before the adoption date contain leases and whether existing leases are operating or finance leases; ASC Topic 842 refers to capital leases as finance leases.

Specifically, for land easement contracts, Xcel Energy has elected the practical expedient provided by *ASU No. 2018-01 Leases: Land Easement Practical Expedient for Transition to Topic 842*, and as a result, only those easement contracts entered on or after Jan. 1, 2019 will be evaluated to determine if lease treatment is appropriate.

Xcel Energy also utilized the transition practical expedient offered by *ASU No. 2018-11 Leases: Targeted Improvements* to implement the standard on a prospective basis. As a result, reporting periods in the consolidated financial statements beginning Jan. 1, 2019 reflect the implementation of ASC Topic 842, while prior periods continue to be reported in accordance with *Leases, Topic 840 (ASC Topic 840)*. Other than first-time recognition of operating leases on its consolidated balance sheet, the implementation of ASC Topic 842 did not have a significant impact on Xcel Energy's consolidated financial statements. Adoption resulted in recognition of approximately $1.7 billion of operating lease ROU assets and current/noncurrent operating lease liabilities.

See Note 12 for leasing disclosures.

3. Property, Plant and Equipment

Major classes of property, plant and equipment

(Millions of Dollars)	Dec. 31, 2019	Dec. 31, 2018
Property, plant and equipment		
Electric plant	$ 44,355	$ 41,472
Natural gas plant	6,560	6,210
Common and other property	2,341	2,154
Plant to be retired [(a)]	259	322
CWIP	2,329	2,091
Total property, plant and equipment	55,844	52,249
Less accumulated depreciation	(16,735)	(15,659)
Nuclear fuel	2,909	2,771
Less accumulated amortization	(2,535)	(2,417)
Property, plant and equipment, net	$ 39,483	$ 36,944

(a) In 2018, the CPUC approved early retirement of PSCo's Comanche Units 1 and 2 in approximately 2022 and 2025, respectively. PSCo also expects Craig Unit 1 to be retired early in 2025. Amounts are presented net of accumulated depreciation.

Joint Ownership of Generation, Transmission and Gas Facilities

The utility subsidiaries' jointly owned assets as of Dec. 31, 2019:

(Millions of Dollars)	Plant in Service	Accumulated Depreciation	CWIP	Percent Owned
NSP-Minnesota				
Electric generation:				
Sherco Unit 3	$ 603	$ 426	$ 4	59%
Sherco common facilities	145	103	2	80
Sherco substation	5	3	—	59
Electric transmission:				
CapX2020	972	92	2	51
Grand Meadow	11	3	—	50
Total NSP-Minnesota	$ 1,736	$ 627	$ 8	

(Millions of Dollars)	Plant in Service	Accumulated Depreciation	CWIP	Percent Owned
NSP-Wisconsin				
Electric transmission:				
La Crosse, WI to Madison, WI	$ 187	$ 7	$ —	37%
CapX2020	169	19	—	80
Total NSP-Wisconsin	$ 356	$ 26	$ —	

(Millions of Dollars)	Plant in Service	Accumulated Depreciation	CWIP	Percent Owned
PSCo				
Electric generation:				
Hayden Unit 1	$ 152	$ 81	$ —	76%
Hayden Unit 2	149	71	—	37
Hayden common facilities	41	22	—	53
Craig Units 1 and 2	81	41	—	10
Craig common facilities	39	22	—	7
Comanche Unit 3	887	149	1	67
Comanche common facilities	29	3	—	82
Electric transmission:				
Transmission and other facilities	174	62	1	Various
Gas transmission:				
Rifle, CO to Avon, CO	22	7	—	60
Gas transmission compressor	9	1	—	50
Total PSCo	$ 1,583	$ 459	$ 2	

Each company's share of operating expenses and construction expenditures is included in the applicable utility accounts. Respective owners are responsible for providing their own financing.

4. Regulatory Assets and Liabilities

Regulatory assets and liabilities are created for amounts that regulators may allow to be collected or may require to be paid back to customers in future electric and natural gas rates. Xcel Energy would be required to recognize the write-off of regulatory assets and liabilities in net income or other comprehensive income if changes in the utility industry no longer allow for the application of regulatory accounting guidance under GAAP.

Components of regulatory assets:

(Millions of Dollars)	See Note(s)	Remaining Amortization Period	Dec. 31, 2019		Dec. 31, 2018	
Regulatory Assets			Current	Noncurrent	Current	Noncurrent
Pension and retiree medical obligations	11	Various	$ 85	$ 1,328	$ 87	$ 1,500
Recoverable deferred taxes on AFUDC recorded in plant		Plant lives	—	271	—	264
Net AROs [(a)]	1, 12	Plant lives	—	269	—	452
Excess deferred taxes — TCJA	7	Various	39	239	—	296
Depreciation differences		One to twelve years	15	140	18	107
Environmental remediation costs	1, 12	Various	36	131	17	155
Benson biomass PPA termination and asset purchase		Ten years	9	73	10	86
Contract valuation adjustments [(b)]	1, 10	Term of related contract	20	62	17	77
Purchased power contract costs		Term of related contract	5	61	4	63
Laurentian biomass PPA termination		Five years	19	54	18	73
PI extended power uprate		Sixteen years	3	53	3	56
Losses on reacquired debt		Term of related debt	4	41	4	44
State commission adjustments		Plant lives	1	31	1	29
Property tax		Various	2	30	14	10
Conservation programs [(c)]	1	One to two years	27	26	42	28
Nuclear refueling outage costs	1	One to two years	43	17	37	14
Sales true-up and revenue decoupling		One to two years	54	16	38	7
Renewable resources and environmental initiatives		One to two years	72	10	39	9
Gas pipeline inspection and remediation costs		One to two years	26	8	28	3
Deferred purchased natural gas and electric energy costs		One to three years	6	6	57	13
Other		Various	22	69	30	40
Total regulatory assets			$ 488	$ 2,935	$ 464	$ 3,326

(a) Includes amounts recorded for future recovery of AROs, less amounts recovered through nuclear decommissioning accruals and gains from decommissioning investments.

(b) Includes the fair value of certain long-term PPAs used to meet energy capacity requirements and valuation adjustments on natural gas commodity purchases.

(c) Includes costs for conservation programs, as well as incentives allowed in certain jurisdictions.

Components of regulatory liabilities:

(Millions of Dollars)	See Note(s)	Remaining Amortization Period	Dec. 31, 2019		Dec. 31, 2018	
Regulatory Liabilities			Current	Noncurrent	Current	Noncurrent
Deferred income tax adjustments and TCJA refunds [(a)]	7	Various	$ 75	$ 3,523	$ 157	$ 3,715
Plant removal costs	1, 12	Plant lives	—	1,217	—	1,175
Effects of regulation on employee benefit costs [(b)]		Various	—	196	—	137
Renewable resources and environmental initiatives		Various	—	45	9	54
ITC deferrals [(c)]	1	Various	—	38	—	40
Deferred electric, natural gas and steam production costs		Less than one year	138	—	102	—
Contract valuation adjustments [(d)]	1, 10	Less than one year	19	—	26	—
Conservation programs [(e)]	1	Less than one year	37	—	36	—
DOE settlement		Less than one year	37	—	19	—
Other		Various	101	58	87	66
Total regulatory liabilities [(f)]			$ 407	$ 5,077	$ 436	$ 5,187

(a) Includes the revaluation of recoverable/regulated plant ADIT and revaluation impact of non-plant ADIT due to the TCJA.

(b) Includes regulatory amortization and certain 2018 TCJA benefits approved by the CPUC to offset the PSCo prepaid pension asset.

(c) Includes impact of lower federal tax rate due to the TCJA.

(d) Includes the fair value of certain long-term PPAs used to meet energy capacity requirements and valuation adjustments on natural gas commodity purchases.

(e) Includes costs for conservation programs, as well as incentives allowed in certain jurisdictions.

(f) Revenue subject to refund of $28 million and $29 million for 2019 and 2018, respectively, is included in other current liabilities.

At Dec. 31, 2019 and 2018, Xcel Energy's regulatory assets not earning a return primarily included the unfunded portion of pension and retiree medical obligations, net AROs and Laurentian biomass PPA termination costs/obligations. In addition, regulatory assets included $544 million and $512 million at Dec. 31, 2019 and 2018, respectively, of past expenditures not earning a return. Amounts primarily related to funded pension obligations, sales true-up and revenue decoupling, purchased natural gas and electric energy costs, various renewable resources and certain environmental initiatives.

5. Borrowings and Other Financing Instruments

Short-Term Borrowings

Short-Term Debt — Xcel Energy meets its short-term liquidity requirements primarily through the issuance of commercial paper and borrowings under their credit facilities and term loan agreements.

Commercial paper and term loan borrowings outstanding:

(Millions of Dollars, Except Interest Rates)	Three Months Ended Dec. 31, 2019	Year Ended Dec. 31 2019	2018	2017
Borrowing limit	$ 3,600	$ 3,600	$ 3,250	$ 3,250
Amount outstanding at period end	595	595	1,038	814
Average amount outstanding	663	1,115	788	644
Maximum amount outstanding	945	1,780	1,349	1,247
Weighted average interest rate, computed on a daily basis	2.40%	2.72%	2.34%	1.35%
Weighted average interest rate at end of period	2.34	2.34	2.97	1.90

Term Loan Agreement — In December 2019, Xcel Energy Inc. entered into a $500 million 364-Day Term Loan Agreement to pay down borrowings and terminate the expiring $500 million term loan made to Xcel Energy under the 364-Day Term Loan Agreement dated as of Dec. 4, 2018. The loan is unsecured and matures Dec. 1, 2020. Xcel Energy has an option to request an extension through Nov. 30, 2021. Term loan includes one financial covenant, requiring Xcel Energy's consolidated funded debt to total capitalization ratio to be less than or equal to 65 percent. Interest is at a rate equal to either the Eurodollar rate, plus 50.0 basis points, or an alternate base rate.

Term loan borrowings as of Dec. 31, 2019:

(Millions of Dollars)	Limit	Amount Used	Available
Xcel Energy Inc.	$ 500	$ 500	$ —

Bilateral Credit Agreement — In March 2019, NSP-Minnesota entered into a one-year uncommitted bilateral credit agreement. The agreement is limited in use to support letters of credit.

As of Dec. 31, 2019, outstanding letters of credit under the Bilateral Credit Agreement were as follows:

(Millions of Dollars)	Limit	Amount Used	Available
NSP-Minnesota	$ 75	$ 22	$ 53

Letters of Credit — Xcel Energy uses letters of credit, typically with terms of one year, to provide financial guarantees for certain operating obligations. As of Dec. 31, 2019 and 2018, there were $20 million and $49 million of letters of credit outstanding under the credit facilities. Amounts approximate their fair value.

Credit Facilities — In order to use commercial paper programs to fulfill short-term funding needs, Xcel Energy Inc. and its utility subsidiaries must have revolving credit facilities in place at least equal to the amount of their respective commercial paper borrowing limits and cannot issue commercial paper in an aggregate amount exceeding available capacity under these credit facilities. The lines of credit provide short-term financing in the form of notes payable to banks, letters of credit and back-up support for commercial paper borrowings.

Amended Credit Agreements — In June 2019, Xcel Energy Inc., NSP-Minnesota, NSP-Wisconsin, PSCo and SPS entered into amended five-year credit agreements with a syndicate of banks. The total borrowing limit under the amended credit agreements was increased to $3.1 billion, with the following changes:

- Maturity extended from June 2021 to June 2024;
- Borrowing limit for Xcel Energy was increased from $1.0 billion to $1.25 billion;
- Borrowing limit for SPS was increased from $400 million to $500 million; and
- Added swingline subfacility for Xcel Energy up to $75 million

Features of the credit facilities:

	Debt-to-Total Capitalization Ratio[a] 2019	2018	Amount Facility May Be Increased (millions)	Additional Periods for Which a One-Year Extension May Be Requested [b]
Xcel Energy Inc. [c]	58%	58%	$ 200	2
NSP-Wisconsin	48	48	N/A	1
NSP-Minnesota	48	48	100	2
SPS	46	46	50	2
PSCo	44	46	100	2

(a) Each credit facility has a financial covenant requiring that the debt-to-total capitalization ratio be less than or equal to 65%.

(b) All extension requests are subject to majority bank group approval.

(c) The Xcel Energy Inc. credit facility has a cross-default provision that Xcel Energy Inc. will be in default on its borrowings under the facility if it or any of its subsidiaries (except NSP-Wisconsin as long as its total assets do not comprise more than 15% of Xcel Energy's consolidated total assets) default on indebtedness in an aggregate principal amount exceeding $75 million.

If Xcel Energy Inc. or its utility subsidiaries do not comply with the covenant, an event of default may be declared, and if not remedied, any outstanding amounts due under the facility can be declared due by the lender. As of Dec. 31, 2019, Xcel Energy Inc. and its subsidiaries were in compliance with all financial covenants.

Xcel Energy Inc. and its utility subsidiaries had the following committed credit facilities available as of Dec. 31, 2019:

(Millions of Dollars)	Credit Facility [a]	Drawn [b]	Available
Xcel Energy Inc.	$ 1,250	$ —	$ 1,250
PSCo	700	9	691
NSP-Minnesota	500	2	498
SPS	500	40	460
NSP-Wisconsin	150	65	85
Total	$ 3,100	$ 116	$ 2,984

(a) These credit facilities mature in June 2024.

(b) Includes outstanding commercial paper and letters of credit.

All credit facility bank borrowings, outstanding letters of credit and outstanding commercial paper reduce the available capacity under the credit facilities. Xcel Energy Inc. and its subsidiaries had no direct advances on facilities outstanding as of Dec. 31, 2019 and 2018.

Long-Term Borrowings and Other Financing Instruments

Generally, all property of NSP-Minnesota, NSP-Wisconsin, PSCo and SPS are subject to the liens of their first mortgage indentures. Debt premiums, discounts and expenses are amortized over the life of the related debt. The premiums, discounts and expenses for refinanced debt are deferred and amortized over the life of the new issuance.

Long term debt obligations for Xcel Energy Inc. and its utility subsidiaries as of Dec. 31 (Millions of Dollars):

Xcel Energy Inc.

Financing Instrument	Interest Rate	Maturity Date	2019	2018
Unsecured senior notes [d]	4.70%	May 15, 2020	$ —	$ 550
Unsecured senior notes	2.40	March 15, 2021	400	400
Unsecured senior notes	2.60	March 15, 2022	300	300
Unsecured senior notes	3.30	June 1, 2025	250	250
Unsecured senior notes	3.30	June 1, 2025	350	350
Unsecured senior notes	3.35	Dec. 1, 2026	500	500
Unsecured senior notes [a]	4.00	June 15, 2028	130	—
Unsecured senior notes [b]	4.00	June 15, 2028	500	500
Unsecured senior notes [a]	2.60	Dec. 1, 2029	500	—
Unsecured senior notes	6.50	July 1, 2036	300	300
Unsecured senior notes	4.80	Sept. 15, 2041	250	250
Unsecured senior notes [a]	3.50	Dec. 1, 2049	500	—
Elimination of PSCo capital lease obligation with affiliates [c]			—	(60)
Unamortized discount			(5)	(5)
Unamortized debt issuance cost			(28)	(21)
Current maturities (capital lease obligation) [c]			—	2
Total long-term debt			$ 3,947	$ 3,316

(a) 2019 financing.

(b) 2018 financing.

(c) Xcel Energy adopted ASC 842 on Jan. 1, 2019, which refers to capital leases as finance leases. Under ASC 842, the present value of future finance lease payments is included in other current liabilities and other noncurrent liabilities rather than debt.

(d) Note was redeemed on Dec. 23, 2019.

NSP-Minnesota

Financing Instrument	Interest Rate	Maturity Date	2019	2018
First mortgage bonds	2.20%	Aug. 15, 2020	$ 300	$ 300
First mortgage bonds	2.15	Aug. 15, 2022	300	300
First mortgage bonds	2.60	May 15, 2023	400	400
First mortgage bonds	7.13	July 1, 2025	250	250
First mortgage bonds	6.50	March 1, 2028	150	150
First mortgage bonds	5.25	July 15, 2035	250	250
First mortgage bonds	6.25	June 1, 2036	400	400
First mortgage bonds	6.20	July 1, 2037	350	350
First mortgage bonds	5.35	Nov. 1, 2039	300	300
First mortgage bonds	4.85	Aug. 15, 2040	250	250
First mortgage bonds	3.40	Aug. 15, 2042	500	500
First mortgage bonds	4.13	May 15, 2044	300	300
First mortgage bonds	4.00	Aug. 15, 2045	300	300
First mortgage bonds	3.60	May 15, 2046	350	350
First mortgage bonds	3.60	Sept. 15, 2047	600	600
First mortgage bonds [a]	2.90	March 1, 2050	600	—
Unamortized discount			(31)	(21)
Unamortized debt issuance cost			(48)	(42)
Current maturities			(300)	—
Total long-term debt			$ 5,221	$ 4,937

(a) 2019 financing.

NSP-Wisconsin

Financing Instrument	Interest Rate	Maturity Date	2019	2018
City of La Crosse resource recovery bond	6.00%	Nov 1, 2021	$ 19	$ 19
First mortgage bonds	3.30	June 15, 2024	100	100
First mortgage bonds	3.30	June 15, 2024	100	100
First mortgage bonds	6.38	Sept. 1, 2038	200	200
First mortgage bonds	3.70	Oct. 1, 2042	100	100
First mortgage bonds	3.75	Dec. 1, 2047	100	100
First mortgage bonds [a]	4.20	Sept. 1, 2048	200	200
Unamortized discount			(3)	(3)
Unamortized debt issuance cost			(8)	(9)
Total long-term debt			$ 808	$ 807

(a) 2018 financing.

PSCo

Financing Instrument	Interest Rate	Maturity Date	2019	2018
First mortgage bonds [d]	5.13%	June 1, 2019	$ —	$ 400
First mortgage bonds	3.20	Nov. 15, 2020	400	400
First mortgage bonds	2.25	Sept. 15, 2022	300	300
First mortgage bonds	2.50	March 15, 2023	250	250
First mortgage bonds	2.90	May 15, 2025	250	250
First mortgage bonds [b]	3.70	June 15, 2028	350	350
First mortgage bonds	6.25	Sept. 1, 2037	350	350
First mortgage bonds	6.50	Aug. 1, 2038	300	300
First mortgage bonds	4.75	Aug. 15, 2041	250	250
First mortgage bonds	3.60	Sept. 15, 2042	500	500
First mortgage bonds	3.95	March 15, 2043	250	250
First mortgage bonds	4.30	March 15, 2044	300	300
First mortgage bonds	3.55	June 15, 2046	250	250
First mortgage bonds	3.80	June 15, 2047	400	400
First mortgage bonds [b]	4.10	June 15, 2048	350	350
First mortgage bonds [a]	4.05	Sept. 15, 2049	400	—
First mortgage bonds [a]	3.20	March 1, 2050	550	—
Capital lease obligations [c]	11.20 - 14.30	2025 - 2060	—	145
Unamortized discount			(24)	(14)
Unamortized debt issuance cost			(41)	(33)
Current maturities			(400)	(406)
Total long-term debt			$ 4,985	$ 4,592

(a) 2019 financing.

(b) 2018 financing.

(c) PSCo adopted ASC 842 on Jan. 1, 2019, which refers to capital leases as finance leases. Under ASC 842, the present value of future finance lease payments is included in other current liabilities and other noncurrent liabilities rather than debt.

(d) Bond was redeemed on March 29, 2019.

SPS

Financing Instrument	Interest Rate	Maturity Date	2019	2018
First mortgage bonds	3.30%	June 15, 2024	$ 150	$ 150
First mortgage bonds	3.30	June 15, 2024	200	200
Unsecured senior notes	6.00	Oct. 1, 2033	100	100
Unsecured senior notes	6.00	Oct. 1, 2036	250	250
First mortgage bonds	4.50	Aug. 15, 2041	200	200
First mortgage bonds	4.50	Aug. 15, 2041	100	100
First mortgage bonds	4.50	Aug. 15, 2041	100	100
First mortgage bonds	3.40	Aug. 15, 2046	300	300
First mortgage bonds	3.70	Aug. 15, 2047	450	450
First mortgage bonds (b)	4.40	Nov. 15, 2048	300	300
First mortgage bonds (a)	3.75	June 15, 2049	300	—
Unamortized discount			(7)	(4)
Unamortized debt issuance cost			(23)	(20)
Total long-term debt			$ 2,420	$ 2,126

(a) 2019 financing.

(b) 2018 financing.

Other Subsidiaries

Financing Instrument	Interest Rate	Maturity Date	2019	2018
Various Eloigne affordable housing project notes	0.00% - 6.90%	2020 — 2052	$ 28	$ 26
Current maturities			(2)	(1)
Total long-term debt			$ 26	$ 25

Maturities of long-term debt:

(Millions of Dollars)	
2020	$ 702
2021	421
2022	900
2023	650
2024	552

Deferred Financing Costs — Deferred financing costs of approximately $148 million and $126 million, net of amortization, are presented as a deduction from the carrying amount of long-term debt as of Dec. 31, 2019 and 2018, respectively.

Forward Equity Agreements — In November 2018, Xcel Energy Inc. entered into forward equity agreements in connection with a completed $459 million public offering of 9.4 million shares of Xcel Energy common stock. In August 2019, Xcel Energy settled the forward equity agreements by physically delivering 9.4 million shares of common equity for cash proceeds of $453 million.

In November 2019, Xcel Energy Inc. entered into forward equity agreements in connection with a completed $743 million public offering of 11.8 million shares of Xcel Energy common stock. The initial forward agreement was for 10.3 million shares with an additional agreement for 1.5 million shares exercised at the option of the banking counterparty.

At Dec. 31, 2019, the forward agreements could have been settled with physical delivery of 11.8 million common shares to the banking counterparty in exchange for cash of $739 million. The forward instruments could also have been settled at Dec. 31, 2019 with delivery of approximately $6 million of cash or approximately 0.1 million shares of common stock to the counterparty, if Xcel Energy unilaterally elected net cash or net share settlement, respectively.

The forward price used to determine amounts due at settlement is calculated based on the November 2019 public offering price for Xcel Energy's common stock of $62.69, increased for the overnight bank funding rate, less a spread of 0.75% and less expected dividends on Xcel Energy's common stock during the period the instruments are outstanding.

Xcel Energy may settle the agreements at any time up to the maturity date of Dec. 31, 2020. Depending on settlement timing, cash proceeds are expected to be approximately $730 million to $740 million.

Forward equity instruments were recognized within stockholders' equity at fair value at execution of the agreements and will not be subsequently adjusted until settlement.

Other Equity — Xcel Energy issued $39 million of equity annually through the DRIP program during the years ended Dec. 31, 2019 and 2018, respectively. Program allows stockholders to elect dividend reinvestment in Xcel Energy common stock through a non-cash transaction. See Note 8 for equity items related to share based compensation.

Capital Stock — Preferred stock authorized/outstanding:

	Preferred Stock Authorized (Shares)	Par Value of Preferred Stock	Preferred Stock Outstanding (Shares) 2019 and 2018
Xcel Energy Inc.	7,000,000	$ 100	—
PSCo	10,000,000	0.01	—
SPS	10,000,000	1.00	—

Xcel Energy Inc. had the following common stock authorized/outstanding:

Common Stock Authorized (Shares)	Par Value of Common Stock	Common Stock Outstanding (Shares) as of Dec. 31, 2019	Common Stock Outstanding (Shares) as of Dec. 31, 2018
1,000,000,000	$ 2.50	524,539,000	514,036,787

Dividend and Other Capital-Related Restrictions — Xcel Energy depends on its subsidiaries to pay dividends. Xcel Energy Inc.'s utility subsidiaries' dividends are subject to the FERC's jurisdiction, which prohibits the payment of dividends out of capital accounts. Dividends are solely to be paid from retained earnings. Certain covenants also require Xcel Energy Inc. to be current on interest payments prior to dividend disbursements.

State regulatory commissions impose dividend limitations for NSP-Minnesota, NSP-Wisconsin and SPS, which are more restrictive than those imposed by the FERC. Requirements and actuals as of Dec. 31, 2019:

	Equity to Total Capitalization Ratio Required Range		Equity to Total Capitalization Ratio Actual
	Low	High	2019
NSP-Minnesota	47.1%	57.5%	52.3%
NSP-Wisconsin	51.5	N/A	51.8
SPS (a)	45.0	55.0	54.4

(a) Excludes short-term debt.

(Amounts in Millions)	Unrestricted Retained Earnings	Total Capitalization	Limit on Total Capitalization
NSP-Minnesota	$ 1,147	$ 11,634	$ 12,700
NSP-Wisconsin (a)	12	1,827	N/A
SPS (b)	535	5,304	N/A

(a) Cannot pay annual dividends in excess of approximately $55 million if its average equity-to-total capitalization ratio falls below the commission authorized level.

(b) May not pay a dividend that would cause a loss of its investment grade bond rating.

Issuance of securities by Xcel Energy Inc. generally is not subject to regulatory approval. However, utility financings and intra-system financings are subject to the jurisdiction of state regulatory commissions and/or the FERC. Xcel Energy may seek additional authorization as necessary.

Amounts authorized to issue as of Dec. 31, 2019:

(Millions of Dollars)	Long-Term Debt	Short-Term Debt
NSP-Minnesota	52.93% of total capitalization (a)	$ 1,905 (a)
NSP-Wisconsin	$ — (b)	150
SPS	— (c)	600
PSCo	150	800

(a) NSP-Minnesota has authorization to issue long-term securities provided the equity-to-total capitalization remains within the required range, and to issue short-term debt provided it does not exceed 15% of total capitalization.

(b) NSP-Wisconsin filed for additional long-term debt authorization in December 2019.

(c) SPS filed for additional long-term debt authorization in February 2020.

6. Revenues

Revenue is classified by the type of goods/services rendered and market/ customer type. Xcel Energy's operating revenues consisted of the following:

	Year Ended Dec. 31, 2019			
(Millions of Dollars)	Electric	Natural Gas	All Other	Total
Major revenue types				
Revenue from contracts with customers:				
Residential	$ 2,877	$ 1,127	$ 41	$ 4,045
C&I	4,844	567	29	5,440
Other	130	—	4	134
Total retail	7,851	1,694	74	9,619
Wholesale	737	—	—	737
Transmission	507	—	—	507
Other	49	120	—	169
Total revenue from contracts with customers	9,144	1,814	74	11,032
Alternative revenue and other	431	54	12	497
Total revenues	$ 9,575	$ 1,868	$ 86	$ 11,529

	Year Ended Dec. 31, 2018			
(Millions of Dollars)	Electric	Natural Gas	All Other	Total
Major revenue types				
Revenue from contracts with customers:				
Residential	$ 2,919	$ 988	$ 38	$ 3,945
C&I	4,874	524	25	5,423
Other	134	—	6	140
Total retail	7,927	1,512	69	9,508
Wholesale	791	—	—	791
Transmission	523	—	—	523
Other	98	100	—	198
Total revenue from contracts with customers	9,339	1,612	69	11,020
Alternative revenue and other	380	127	10	517
Total revenues	$ 9,719	$ 1,739	$ 79	$ 11,537

7. Income Taxes

Federal Tax Reform — In 2017, the TCJA was signed into law. The key provisions impacting Xcel Energy, generally beginning in 2018, included:

- Corporate federal tax rate reduction from 35% to 21%;
- Normalization of resulting plant-related excess deferred taxes;
- Elimination of the corporate alternative minimum tax;
- Continued interest expense deductibility and discontinued bonus depreciation for regulated public utilities;
- Limitations on certain executive compensation deductions;
- Limitations on certain deductions for NOLs arising after Dec. 31, 2017 (limited to 80% of taxable income);
- Repeal of the section 199 manufacturing deduction; and
- Reduced deductions for meals and entertainment as well as state and local lobbying.

Reductions in deferred tax assets and liabilities due to a decrease in corporate federal tax rates typically result in a net tax benefit. However, the impacts are primarily recognized as regulatory liabilities refundable to utility customers as a result of IRS requirements and past regulatory treatment.

Estimated impacts of the new tax law in December 2017 included:

- $2.7 billion ($3.8 billion grossed-up for tax) of reclassifications of plant-related excess deferred taxes to regulatory liabilities upon valuation at the new 21% federal rate. The regulatory liabilities will be amortized consistent with IRS normalization requirements, resulting in customer refunds over an estimated weighted average period of approximately 30 years;
- $254 million and $174 million of reclassifications (grossed-up for tax) of excess deferred taxes for non-plant related deferred tax assets and liabilities, respectively, to regulatory assets and liabilities; and
- $23 million of total estimated income tax expense related to the tax rate change on certain non-plant deferred taxes and all other 2017 income statement impacts of the federal tax reform.

Xcel Energy accounted for the state tax impacts of federal tax reform based on enacted state tax laws. Any future state tax law changes related to the TCJA will be accounted for in the periods state laws are enacted.

Federal Audit — Statute of limitations applicable to Xcel Energy's consolidated federal income tax returns:

Tax Year(s)	Expiration
2009 - 2013	June 2020
2014 - 2016	September 2020

In 2015, the IRS commenced an examination of tax years 2012 and 2013. In 2017, the IRS concluded the audit of tax years 2012 and 2013 and proposed an adjustment that would impact Xcel Energy's NOL and ETR. Xcel Energy filed a protest with the IRS. As of Dec. 31, 2019, the case has been forwarded to the Office of Appeals and Xcel Energy has recognized its best estimate of income tax expense that will result from a final resolution of this issue; however, the outcome and timing of a resolution is unknown.

In 2018, the IRS began an audit of tax years 2014 - 2016. As of Dec. 31, 2019, no adjustments have been proposed.

State Audits — Xcel Energy files consolidated state tax returns based on income in its major operating jurisdictions and various other state income-based tax returns.

As of Dec. 31, 2019, Xcel Energy's earliest open tax years (subject to examination by state taxing authorities in its major operating jurisdictions) were as follows:

State	Year
Colorado	2009
Minnesota	2009
Texas	2009
Wisconsin	2014

- In 2018, Wisconsin began an audit of tax years 2014 - 2016. As of Dec. 31, 2019, no material adjustments have been proposed.
- Xcel Energy had no other state income tax audits in progress for its major operating jurisdictions as of Dec. 31, 2019.

Unrecognized Tax Benefits — Unrecognized tax benefit balance includes permanent tax positions, which if recognized would affect the annual ETR. In addition, the unrecognized tax benefit balance includes temporary tax positions for which the ultimate deductibility is highly certain, but for which there is uncertainty about the timing of such deductibility. A change in the period of deductibility would not affect the ETR but would accelerate the payment to the taxing authority to an earlier period.

Unrecognized tax benefits - permanent vs. temporary:

(Millions of Dollars)	Dec. 31, 2019	Dec. 31, 2018
Unrecognized tax benefit — Permanent tax positions	$ 35	$ 28
Unrecognized tax benefit — Temporary tax positions	9	9
Total unrecognized tax benefit	$ 44	$ 37

Changes in unrecognized tax benefits:

(Millions of Dollars)	2019	2018	2017
Balance at Jan. 1	$ 37	$ 39	$ 134
Additions based on tax positions related to the current year	10	9	6
Reductions based on tax positions related to the current year	(4)	(4)	(4)
Additions for tax positions of prior years	1	2	15
Reductions for tax positions of prior years	—	(4)	(105)
Settlements with taxing authorities	—	(5)	(7)
Balance at Dec. 31	$ 44	$ 37	$ 39

Unrecognized tax benefits were reduced by tax benefits associated with NOL and tax credit carryforwards:

(Millions of Dollars)	Dec. 31, 2019	Dec. 31, 2018
NOL and tax credit carryforwards	$ (40)	$ (35)

Net deferred tax liability associated with the unrecognized tax benefit amounts and related NOLs and tax credits carryforwards were $29 million and $24 million at Dec. 31, 2019 and Dec. 31, 2018, respectively.

As the IRS Appeals and federal and state audits progress and other state audits resume, it is reasonably possible that the amount of unrecognized tax benefit could decrease up to approximately $28 million in the next 12 months.

Payable for interest related to unrecognized tax benefits is partially offset by the interest benefit associated with NOL and tax credit carryforwards.

No amounts were payable for interest related to unrecognized tax benefits as of Dec. 31, 2019, 2018 or 2017. No interest income related to unrecognized tax benefits was recorded in 2019 or 2018, and $3 million was recorded in 2017.

No amounts were accrued for penalties related to unrecognized tax benefits as of Dec. 31, 2019, 2018 or 2017.

Other Income Tax Matters — NOL amounts represent the tax loss that is carried forward and tax credits represent the deferred tax asset. NOL and tax credit carryforwards as of Dec. 31:

(Millions of Dollars)	2019	2018
Federal tax credit carryforwards	$ 639	$ 553
Valuation allowances for federal credit carryforwards	—	(5)
State NOL carryforwards	937	1,104
Valuation allowances for state NOL carryforwards	(19)	(50)
State tax credit carryforwards, net of federal detriment [(a)]	89	89
Valuation allowances for state credit carryforwards, net of federal benefit [(b)]	(66)	(69)

(a) State tax credit carryforwards are net of federal detriment of $24 million as of Dec. 31, 2019 and 2018.

(b) Valuation allowances for state tax credit carryforwards were net of federal benefit of $17 million and $18 million as of Dec. 31, 2019 and 2018, respectively.

Federal carryforward periods expire between 2023 and 2039 and state carryforward periods expire between 2020 and 2036.

Total income tax expense from operations differs from the amount computed by applying the statutory federal income tax rate to income before income tax expense.

Effective income tax rate for years ended Dec. 31:

	2019	2018 [(a)]	2017 [(a)]
Federal statutory rate	21.0%	21.0%	35.0%
State income tax on pretax income, net of federal tax effect	4.9	5.0	4.1
Increases (decreases) in tax from:			
Wind PTCs	(9.4)	(5.2)	(4.7)
Plant regulatory differences [(b)]	(5.8)	(6.2)	(0.8)
Other tax credits, net of NOL & tax credit allowances	(1.7)	(1.7)	(1.0)
Change in unrecognized tax benefits	0.5	0.4	(0.6)
Tax reform	—	—	1.4
Other, net	(1.0)	(0.7)	(1.3)
Effective income tax rate	8.5%	12.6%	32.1%

(a) Prior periods have been reclassified to conform to current year presentation.

(b) Regulatory differences for income tax primarily relate to the credit of excess deferred taxes to customers through the average rate assumption method. Income tax benefits associated with the credit of excess deferred credits are offset by corresponding revenue reductions and additional prepaid pension asset amortization.

Components of income tax expense for years ended Dec. 31:

(Millions of Dollars)	2019	2018	2017
Current federal tax (benefit) expense	$ (16)	$ (34)	$ 1
Current state tax expense (benefit)	4	8	(11)
Current change in unrecognized tax expense (benefit)	2	(6)	(83)
Deferred federal tax expense	55	122	460
Deferred state tax expense	83	85	107
Deferred change in unrecognized tax expense	5	11	73
Deferred ITCs	(5)	(5)	(5)
Total income tax expense	$ 128	$ 181	$ 542

Components of deferred income tax expense as of Dec. 31:

(Millions of Dollars)	2019	2018	2017
Deferred tax expense (benefit) excluding items below	$ 344	$ 320	$ (2,939)
Amortization and adjustments to deferred income taxes on income tax regulatory assets and liabilities	(206)	(102)	3,583
Tax benefit (expense) allocated to other comprehensive income, net of adoption of ASU No. 2018-02, and other	5	—	(4)
Deferred tax expense	$ 143	$ 218	$ 640

Components of net deferred tax liability as of Dec. 31:

(Millions of Dollars)	2019	2018 [(a)]
Deferred tax liabilities:		
Differences between book and tax bases of property	$ 5,474	$ 5,082
Operating lease assets	449	—
Regulatory assets	598	599
Pension expense	173	178
Other	70	60
Total deferred tax liabilities	$ 6,764	$ 5,919
Deferred tax assets:		
Regulatory liabilities	$ 847	$ 879
Operating lease liabilities	449	—
Tax credit carryforward	727	642
NOL carryforward	38	51
NOL and tax credit valuation allowances	(67)	(79)
Other employee benefits	128	124
Deferred ITCs	14	16
Rate refund	26	60
Other	93	61
Total deferred tax assets	$ 2,255	$ 1,754
Net deferred tax liability	$ 4,509	$ 4,165

(a) Prior periods have been reclassified to conform to current year presentation.

8. Share-Based Compensation

Incentive Plans Including Share-Based Compensation — Xcel Energy has two incentive plans which include share-based payment elements. Plans and authorized equity shares for awards:

- Omnibus Incentive Plan - 7.0 million shares; and
- Executive Annual Incentive Award Plan - 1.2 million shares.

Restricted Stock — The Executive Annual Incentive Award Plan and Omnibus Incentive Plan allow certain employees to elect to receive shares of common or restricted stock. Restricted stock is treated as an equity award and vests and settles in equal annual installments over a three-year period. Restricted stock has a fair value equal to the market trading price of Xcel Energy stock at the grant date.

Shares of restricted stock granted at Dec. 31:

(Shares in Thousands)	2019	2018	2017
Granted shares	13	18	15
Grant date fair value	$ 53.46	$ 44.68	$ 42.00

Changes in nonvested restricted stock:

(Shares in Thousands)	Shares	Weighted Average Grant Date Fair Value
Nonvested restricted stock at Jan. 1, 2019	36	$ 44.29
Granted	13	53.46
Forfeited	—	—
Vested	(19)	41.60
Dividend equivalents	1	57.09
Nonvested restricted stock at Dec. 31, 2019	31	50.15

Other Equity Awards — Xcel Energy's Board of Directors has granted equity awards under the Omnibus Incentive Plan, which includes various vesting conditions and performance goals. At the end of the restricted period, such grants will be awarded if vesting conditions and/or performance goals are met.

Certain employees are granted equity awards with a portion subject only to service conditions, and the other portion subject to performance conditions. A total of 0.3 million time-based equity shares subject only to service conditions were granted annually in 2019, 2018 and 2017, respectively.

The performance conditions for a portion of the awards granted from 2017 to 2019 are based on relative TSR and environmental goals. Equity awards with performance conditions will be settled or forfeited after three years, with payouts ranging from zero to 200 percent depending on achievement.

Equity award units granted to employees (excluding restricted stock):

(Units in Thousands)	2019	2018	2017
Granted units	483	500	503
Weighted average grant date fair value	$ 49.67	$ 47.60	$ 41.02

Equity awards vested:

(Units in Thousands)	2019	2018	2017
Vested Units	464	475	467
Total Fair Value	$ 29,432	$ 23,393	$ 22,459

Changes in the nonvested portion of equity award units:

(Units in Thousands)	Units	Weighted Average Grant Date Fair Value
Nonvested Units at Jan. 1, 2019	939	$ 44.30
Granted	483	49.67
Forfeited	(116)	50.19
Vested	(464)	41.09
Dividend equivalents	38	45.22
Nonvested Units at Dec. 31, 2019	880	48.20

Stock Equivalent Units — Non-employee members of Xcel Energy's Board of Directors may elect to receive their annual equity grant as stock equivalent units in lieu of common stock. Each unit's value is equal to one share of common stock. The annual equity grant is vested as of the date of each member's election to the Board of Directors; there is no further service or other condition. Directors may also elect to receive their cash fees as stock equivalent units in lieu of cash. Stock equivalent units are payable as a distribution of common stock upon a director's termination of service.

Stock equivalent units granted:

(Units in Thousands)	2019	2018	2017
Granted units	29	36	51
Weighted average grant date fair value	$ 58.44	$ 45.44	$ 46.05

Changes in stock equivalent units:

(Units in Thousands)	Units	Weighted Average Grant Date Fair Value
Stock equivalent units at Jan. 1, 2019	688	$ 30.93
Granted	29	58.44
Units distributed	(11)	32.56
Dividend equivalents	19	57.28
Stock equivalent units at Dec. 31, 2019	725	32.72

TSR Liability Awards — Xcel Energy Inc.'s Board of Directors has granted TSR liability awards under the Omnibus Incentive Plan. This plan allows Xcel Energy to attach various performance goals to the awards granted. The liability awards have been historically dependent on relative TSR measured over a three-year period. Xcel Energy Inc.'s TSR is compared to a peer group of 20 other utility members. Potential payouts of the awards range from zero to 200%.

TSR liability awards granted:

(In Thousands)	2019	2018	2017
Awards granted	225	239	240

TSR liability awards settled:

(In Thousands)	2019	2018	2017
Awards settled	466	482	454
Settlement amount (cash, common stock and deferred amounts)	$ 24,930	$ 21,534	$ 19,083

TSR liability awards of $21 million were settled in cash in 2019.

Share-Based Compensation Expense — Other than for restricted stock, vesting of employee equity awards is typically predicated on the achievement of a TSR or environmental measures target. Additionally, approximately 0.3 million of equity award units were granted annually in 2017 - 2019, with vesting subject only to service conditions of three years.

Generally, these instruments are considered to be equity awards as the award settlement determination (shares or cash) is made by Xcel Energy, not the participants. In addition, these awards have not been previously settled in cash and Xcel Energy plans to continue electing share settlement.

Grant date fair value of equity awards is expensed over the service period. TSR liability awards have been historically settled partially in cash, and do not qualify as equity awards, but rather are accounted for as liabilities. As liability awards, the fair value on which ratable expense is based, as employees vest in their rights to those awards, is remeasured each period based on the current stock price and performance achievement, and final expense is based on the market value of the shares on the date the award is settled.

Compensation costs related to share-based awards:

(Millions of Dollars)	2019	2018	2017
Compensation cost for share-based awards [(a)]	$ 58	$ 45	$ 57
Tax benefit recognized in income	15	12	22

(a) Compensation costs for share-based payment are included in O&M expense.

There was approximately $40 million in 2019 and $38 million in 2018 of total unrecognized compensation cost related to nonvested share-based compensation awards. Xcel Energy expects to recognize the unrecognized amount over a weighted average period of 1.6 years.

9. Earnings Per Share

Basic EPS was computed by dividing the earnings available to common shareholders by the weighted average number of common shares outstanding during the period. Diluted EPS was computed by dividing the earnings available to common shareholders by the diluted weighted average number of common shares outstanding during the period. Diluted EPS reflects the potential dilution that could occur if securities or other agreements to issue common stock (i.e., common stock equivalents) were settled. The weighted average number of potentially dilutive shares outstanding used to calculate diluted EPS is calculated using the treasury stock method.

Common Stock Equivalents — Xcel Energy Inc. has common stock equivalents related to forward equity agreements and certain equity awards in share-based compensation arrangements. Common stock equivalents include commitments to issue common stock related to time-based equity compensation awards.

Stock equivalent units granted to Xcel Energy's Board of Directors are included in common shares outstanding upon grant date as there is no further service, performance or market condition associated with these. Restricted stock issued to employees under the Executive Annual Incentive Award Plan is included in common shares outstanding when granted.

Share-based compensation arrangements for which there is currently no dilutive impact to EPS include the following:

- Equity awards subject to a performance condition; included in common shares outstanding when all necessary conditions for settlement have been satisfied by the end of the reporting period; and
- Liability awards subject to a performance condition; any portions settled in shares are included in common shares outstanding upon settlement.

Diluted common shares outstanding included common stock equivalents of 1.3 million, 0.5 million and 0.6 million shares for 2019, 2018 and 2017.

10. Fair Value of Financial Assets and Liabilities

Fair Value Measurements

Accounting guidance for fair value measurements and disclosures provides a single definition of fair value and requires disclosures about assets and liabilities measured at fair value. A hierarchical framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value is established by this guidance.

- Level 1 — Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. The types of assets and liabilities included in Level 1 are highly liquid and actively traded instruments with quoted prices;
- Level 2 — Pricing inputs are other than quoted prices in active markets but are either directly or indirectly observable as of the reporting date. The types of assets and liabilities included in Level 2 are typically either comparable to actively traded securities or contracts or priced with models using highly observable inputs; and
- Level 3 — Significant inputs to pricing have little or no observability as of the reporting date. The types of assets and liabilities included in Level 3 are those valued with models requiring significant management judgment or estimation.

Specific valuation methods include:

Cash equivalents — The fair values of cash equivalents are generally based on cost plus accrued interest; money market funds are measured using quoted NAV.

Investments in equity securities and other funds — Equity securities are valued using quoted prices in active markets. The fair values for commingled funds are measured using NAVs. The investments in commingled funds may be redeemed for NAV with proper notice. Private equity commingled fund investments require approval of the fund for any unscheduled redemption, and such redemptions may be approved or denied by the fund at its sole discretion. Unscheduled distributions from real estate commingled funds investments may be redeemed with proper notice, however, withdrawals may be delayed or discounted as a result of fund illiquidity.

Investments in debt securities — Fair values for debt securities are determined by a third-party pricing service using recent trades and observable spreads from benchmark interest rates for similar securities.

Interest rate derivatives — Fair values of interest rate derivatives are based on broker quotes that utilize current market interest rate forecasts.

Commodity derivatives — Methods used to measure the fair value of commodity derivative forwards and options utilize forward prices and volatilities, as well as pricing adjustments for specific delivery locations, and are generally assigned a Level 2 classification. When contractual settlements relate to inactive delivery locations or extend to periods beyond those readily observable on active exchanges or quoted by brokers, the significance of the use of less observable forecasts of forward prices and volatilities on a valuation is evaluated and may result in Level 3 classification.

Electric commodity derivatives held by NSP-Minnesota and SPS include transmission congestion instruments, generally referred to as FTRs. FTRs purchased from a RTO are financial instruments that entitle or obligate the holder to monthly revenues or charges based on transmission congestion across a given transmission path.

The value of an FTR is derived from, and designed to offset, the cost of transmission congestion. In addition to overall transmission load, congestion is also influenced by the operating schedules of power plants and the consumption of electricity pertinent to a given transmission path. Unplanned plant outages, scheduled plant maintenance, changes in the relative costs of fuels used in generation, weather and overall changes in demand for electricity can each impact the operating schedules of the power plants on the transmission grid and the value of an FTR.

If forecasted costs of electric transmission congestion increase or decrease for a given FTR path, the value of that particular FTR instrument will likewise increase or decrease. Given the limited observability of certain inputs to the value of FTRs between auction processes, including expected plant operating schedules and retail and wholesale demand, fair value measurements for FTRs have been assigned a Level 3.

Non-trading monthly FTR settlements are included in fuel and purchased energy cost recovery mechanisms as applicable in each jurisdiction, and therefore changes in the fair value of the yet to be settled portions of most FTRs are deferred as a regulatory asset or liability. Given this regulatory treatment and the limited magnitude of FTRs relative to the electric utility operations of NSP-Minnesota and SPS, the numerous unobservable quantitative inputs pertinent to the value of FTRs are immaterial to the consolidated financial statements.

Non-Derivative Fair Value Measurements

Nuclear Decommissioning Fund

The NRC requires NSP-Minnesota to maintain a portfolio of investments to fund the costs of decommissioning its nuclear generating plants. Assets of the nuclear decommissioning fund are legally restricted for the purpose of decommissioning these facilities. The fund contains cash equivalents, debt securities, equity securities and other investments. NSP-Minnesota uses the MPUC approved asset allocation for the escrow and investment targets by asset class for both the escrow and qualified trust.

NSP-Minnesota recognizes the costs of funding the decommissioning over the lives of the nuclear plants, assuming rate recovery of all costs. Realized and unrealized gains on fund investments over the life of the fund are deferred as an offset of NSP-Minnesota's regulatory asset for nuclear decommissioning costs. Consequently, any realized and unrealized gains and losses on securities in the nuclear decommissioning fund are deferred as a component of the regulatory asset.

Unrealized gains for the nuclear decommissioning fund were $706 million and $450 million as of Dec. 31, 2019 and 2018, respectively, and unrealized losses were $6 million and $45 million as of Dec. 31, 2019 and 2018, respectively.

Non-derivative instruments with recurring fair value measurements:

	Dec. 31, 2019					
		Fair Value				
(Millions of Dollars)	**Cost**	**Level 1**	**Level 2**	**Level 3**	**NAV**	**Total**
Nuclear decommissioning fund [(a)]						
Cash equivalents	$ 33	$ 33	$ —	$ —	$ —	$ 33
Commingled funds	733	—	—	—	935	935
Debt securities	489	—	495	13	—	508
Equity securities	485	962	2	—	—	964
Total	$ 1,740	$ 995	$ 497	$ 13	$ 935	$ 2,440

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet, which also includes $155 million of equity investments in unconsolidated subsidiaries and $136 million of rabbi trust assets and miscellaneous investments.

	Dec 31, 2018					
		Fair Value				
(Millions of Dollars)	**Cost**	**Level 1**	**Level 2**	**Level 3**	**NAV**	**Total**
Nuclear decommissioning fund [(a)]						
Cash equivalents	$ 24	$ 24	$ —	$ —	$ —	$ 24
Commingled funds	758	79	—	—	819	898
Debt securities	466	—	436	—	—	436
Equity securities	401	697	—	—	—	697
Total	$ 1,649	$ 800	$ 436	$ —	$ 819	$ 2,055

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet, which also includes $141 million of equity investments in unconsolidated subsidiaries and $121 million of rabbi trust assets and miscellaneous investments.

For the years ended Dec. 31, 2019 and 2018, there were immaterial Level 3 nuclear decommissioning fund investments or transfer of amounts between levels.

Contractual maturity dates of debt securities in the nuclear decommissioning fund as of Dec. 31, 2019:

	Final Contractual Maturity				
(Millions of Dollars)	Due in 1 Year or Less	Due in 1 to 5 Years	Due in 5 to 10 Years	Due after 10 Years	Total
Debt securities	$ (7)	$ 111	$ 246	$ 158	$ 508

Rabbi Trusts

Xcel Energy has established rabbi trusts to provide partial funding for future distributions of its SERP and deferred compensation plan.

Cost and fair value of assets held in rabbi trusts:

	December 31, 2019				
		Fair Value			
(Millions of Dollars)	Cost	Level 1	Level 2	Level 3	Total
Rabbi Trusts [(a)]					
Cash equivalents	$ 17	$ 17	$ —	$ —	$ 17
Mutual funds	57	65	—	—	65
Total	$ 74	$ 82	$ —	$ —	$ 82

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet.

	Dec. 31, 2018				
		Fair Value			
(Millions of Dollars)	Cost	Level 1	Level 2	Level 3	Total
Rabbi Trusts [(a)]					
Cash equivalents	$ 16	$ 16	$ —	$ —	$ 16
Mutual funds	52	51	—	—	51
Total	$ 68	$ 67	$ —	$ —	$ 67

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet.

Derivative Fair Value Measurements

Xcel Energy enters into derivative instruments, including forward contracts, futures, swaps and options, for trading purposes and to manage risk in connection with changes in interest rates, utility commodity prices and vehicle fuel prices.

Interest Rate Derivatives — Xcel Energy enters into various instruments that effectively fix the interest payments on certain floating rate debt obligations or effectively fix the yield or price on a specified benchmark interest rate for an anticipated debt issuance for a specific period. These derivative instruments are generally designated as cash flow hedges for accounting purposes.

As of Dec. 31, 2019, accumulated other comprehensive losses related to interest rate derivatives included $5 million of net losses expected to be reclassified into earnings during the next 12 months as the hedged transactions impact earnings.

As of Dec. 31, 2019, Xcel Energy had no unsettled interest rate swaps outstanding. These interest rate derivatives were designated as hedges, and as such, changes in fair value are recorded to other comprehensive income.

Wholesale and Commodity Trading Risk — Xcel Energy Inc.'s utility subsidiaries conduct various wholesale and commodity trading activities, including the purchase and sale of electric capacity, energy, energy-related instruments and natural gas-related instruments, including derivatives. Xcel Energy is allowed to conduct these activities within guidelines and limitations as approved by its risk management committee, comprised of management personnel not directly involved in activities governed by this policy.

Commodity Derivatives — Xcel Energy enters into derivative instruments to manage variability of future cash flows from changes in commodity prices in its electric and natural gas operations, as well as for trading purposes. This could include the purchase or sale of energy or energy-related products, natural gas to generate electric energy, natural gas for resale, FTRs, vehicle fuel and weather derivatives.

As of Dec. 31, 2019, Xcel Energy had no commodity derivative contracts designated as cash flow hedges. Xcel Energy may enter into derivative instruments that mitigate commodity price risk on behalf of electric and natural gas customers but may not be designated as qualifying hedging transactions. Changes in the fair value of non-trading commodity derivative instruments are recorded in other comprehensive income or deferred as a regulatory asset or liability. The classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms. Immaterial amounts to income related to the ineffectiveness of cash flow hedges were recorded for the years ended Dec. 31, 2019 and 2018.

As of Dec. 31, 2019, there were no net gains related to commodity derivative cash flow hedges recorded as a component of accumulated other comprehensive losses or related amounts expected to be reclassified into earnings during the next 12 months.

Xcel Energy enters into commodity derivative instruments for trading purposes not directly related to commodity price risks associated with serving its electric and natural gas customers. Changes in the fair value of these commodity derivatives are recorded in electric operating revenues, net of amounts credited to customers under margin-sharing mechanisms.

Gross notional amount of commodity forwards, options and FTRs at Dec. 31:

(Millions of Dollars) [(a) (b)]	2019	2018
MWh of electricity	95	87
MMBtu of natural gas	110	92

(a) Amounts are not reflective of net positions in the underlying commodities.

(b) Notional amounts for options are included on a gross basis but weighted for the probability of exercise.

Consideration of Credit Risk and Concentrations — Xcel Energy continuously monitors the creditworthiness of counterparties to its interest rate derivatives and commodity derivative contracts prior to settlement and assesses each counterparty's ability to perform on the transactions set forth in the contracts. Impact of credit risk was immaterial to the fair value of unsettled commodity derivatives presented in the consolidated balance sheets.

Xcel Energy's utility subsidiaries' most significant concentrations of credit risk with particular entities or industries are contracts with counterparties to their wholesale, trading and non-trading commodity activities.

As of Dec. 31, 2019, six of Xcel Energy's 10 most significant counterparties for these activities, comprising $154 million or 60% of this credit exposure, had investment grade credit ratings from Standard & Poor's, Moody's Investor Services or Fitch Ratings. Four of the 10 most significant counterparties, comprising $37 million or 14% of this credit exposure, were not rated by these external agencies, but based on Xcel Energy's internal analysis, had credit quality consistent with investment grade. Nine of these significant counterparties are municipal or cooperative electric entities, RTOs or other utilities.

Qualifying Cash Flow Hedges — Financial impact of qualifying interest rate and vehicle fuel cash flow hedges on Xcel Energy's accumulated other comprehensive loss, included in the consolidated statements of common stockholders' equity and in the consolidated statements of comprehensive income:

(Millions of Dollars)	2019	2018	2017
Accumulated other comprehensive loss related to cash flow hedges at Jan. 1	$ (60)	$ (58)	$ (51)
After-tax net unrealized losses related to derivatives accounted for as hedges	(23)	(5)	—
After-tax net realized losses on derivative transactions reclassified into earnings	3	3	3
Adoption of ASU. 2018-02 [a]	—	—	(10)
Accumulated other comprehensive loss related to cash flow hedges at Dec. 31	$ (80)	$ (60)	$ (58)

(a) In 2017, Xcel Energy implemented ASU No 2018-02 related to TCJA, which resulted in reclassification of certain credit balances within net accumulated other comprehensive loss to retained earnings.

Impact of derivative activity:

	Pre-Tax Fair Value Gains (Losses) Recognized During the Period in:	
(Millions of Dollars)	Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities
Year Ended Dec. 31, 2019		
Derivatives designated as cash flow hedges		
Interest rate	$ (30)	$ —
Total	(30)	—
Other derivative instruments		
Electric commodity	—	8
Natural gas commodity	—	(9)
Total	—	(1)
Year Ended Dec. 31, 2018		
Interest rate	(7)	—
Total	(7)	—
Other derivative instruments		
Electric commodity	—	1
Natural gas commodity	—	10
Total	—	11
Year Ended Dec. 31, 2017		
Other derivative instruments		
Electric commodity	—	10
Natural gas commodity	—	(13)
Total	$ —	$ (3)

	Pre-Tax (Gains) Losses Reclassified into Income During the Period from:		
(Millions of Dollars)	Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	Pre-Tax Gains (Losses) Recognized During the Period in Income
Year Ended Dec. 31, 2019			
Derivatives designated as cash flow hedges			
Interest rate	$ 4 [a]	$ —	$ —
Total	4	—	—
Other derivative instruments			
Commodity trading	—	—	2 [b]
Electric commodity	—	(5) [c]	—
Natural gas commodity	—	2 [d]	(7) [d]
Total	—	(3)	(5)
Year Ended Dec. 31, 2018			
Derivatives designated as cash flow hedges			
Interest rate	4 [a]	—	—
Total	4	—	—
Other derivative instruments			
Commodity trading	—	—	14 [b]
Electric commodity	—	(1) [c]	—
Natural gas commodity	—	(6) [d]	(4) [d]
Total	—	(7)	10
Year Ended Dec. 31, 2017			
Derivatives designated as cash flow hedges			
Interest rate	5 [a]	—	—
Total	5	—	—
Other derivative instruments			
Commodity trading	—	—	10 [b]
Electric commodity	—	(15) [c]	—
Natural gas commodity	—	3 [d]	(6) [d]
Total	$ —	$ (12)	$ 4

(a) Amounts recorded to interest charges.

(b) Amounts recorded to electric operating revenues. Portions of these gains and losses are subject to sharing with electric customers through margin-sharing mechanisms and deducted from gross revenue, as appropriate.

(c) Amounts recorded to electric fuel and purchased power. These derivative settlement gains and losses are shared with electric customers through fuel and purchased energy cost-recovery mechanisms and reclassified out of income as regulatory assets or liabilities, as appropriate.

(d) Amounts for the year ended Dec. 31, 2019 included no settlement losses on derivatives entered to mitigate natural gas price risk for electric generation recorded to electric fuel and purchased power, subject to cost-recovery mechanisms and reclassified to a regulatory asset, as appropriate. Such losses and gains for the years ended Dec. 31, 2018 and 2017 were $1 million and immaterial, respectively. Remaining settlement losses for the years ended Dec. 31, 2019, 2018 and 2017 related to natural gas operations and were recorded to cost of natural gas sold and transported. These losses are subject to cost-recovery mechanisms and reclassified out of income to a regulatory asset, as appropriate.

Xcel Energy had no derivative instruments designated as fair value hedges during the years ended Dec. 31, 2019, 2018 and 2017.

Credit Related Contingent Features — Contract provisions for derivative instruments that the utility subsidiaries enter, including those accounted for as normal purchase-normal sale contracts and therefore not reflected on the consolidated balance sheets, may require the posting of collateral or settlement of the contracts for various reasons, including if the applicable utility subsidiary's credit ratings are downgraded below its investment grade credit rating by any of the major credit rating agencies, or for cross default contractual provisions if there was a failure under other financing arrangements related to payment terms or other covenants. As of Dec. 31, 2019 and 2018, the amounts for derivative instruments in a liability position with such underlying contract provisions were $7 million and none, respectively.

Certain derivative instruments are also subject to contract provisions that contain adequate assurance clauses. These provisions allow counterparties to seek performance assurance, including cash collateral, in the event that a given utility subsidiary's ability to fulfill its contractual obligations is reasonably expected to be impaired. Xcel Energy had no collateral posted related to adequate assurance clauses in derivative contracts as of Dec. 31, 2019 and 2018.

Recurring Fair Value Measurements — Xcel Energy's derivative assets and liabilities measured at fair value on a recurring basis:

	Dec. 31, 2019						Dec. 31, 2018					
	Fair Value						Fair Value					
(Millions of Dollars)	Level 1	Level 2	Level 3	Fair Value Total	Netting [(a)]	Total	Level 1	Level 2	Level 3	Fair Value Total	Netting [(a)]	Total
Current derivative assets												
Commodity trading	$ 3	$ 51	$ 24	$ 78	$ (52)	$ 26	$ 4	$ 92	$ 2	$ 98	$ (44)	$ 54
Electric commodity	—	—	21	21	(1)	20	—	—	25	25	—	25
Natural gas commodity	—	6	—	6	—	6	—	4	—	4	—	4
Total current derivative assets	$ 3	$ 57	$ 45	$ 105	$ (53)	52	$ 4	$ 96	$ 27	$ 127	$ (44)	83
PPAs [(b)]						3						4
Current derivative instruments						$ 55						$ 87
Noncurrent derivative assets												
Other derivative instruments:												
Commodity trading	$ 9	$ 38	$ 7	$ 54	$ (45)	$ 9	$ —	$ 27	$ 5	$ 32	$ (14)	$ 18
Total noncurrent derivative assets	$ 9	$ 38	$ 7	$ 54	$ (45)	9	$ —	$ 27	$ 5	$ 32	$ (14)	18
PPAs [(b)]						13						16
Noncurrent derivative instruments						$ 22						$ 34

	Dec. 31, 2019						Dec. 31, 2018					
	Fair Value						Fair Value					
(Millions of Dollars)	Level 1	Level 2	Level 3	Fair Value Total	Netting [(a)]	Total	Level 1	Level 2	Level 3	Fair Value Total	Netting [(a)]	Total
Current derivative liabilities												
Derivatives designated as cash flow hedges:												
Interest rate	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 7	$ —	$ 7	$ —	$ 7
Other derivative instruments:												
Commodity trading	4	59	15	78	(63)	15	4	88	2	94	(60)	34
Electric commodity	—	—	1	1	(1)	—	—	—	—	—	—	—
Natural gas commodity	—	5	—	5	—	5	—	—	—	—	—	—
Total current derivative liabilities	$ 4	$ 64	$ 16	$ 84	$ (64)	20	$ 4	$ 95	$ 2	$ 101	$ (60)	41
PPAs [(b)]						18						20
Current derivative instruments						$ 38						$ 61
Noncurrent derivative liabilities												
Other derivative instruments:												
Commodity trading	$ 2	$ 79	$ 32	$ 113	$ (13)	$ 100	$ —	$ 18	$ 1	$ 19	$ 17	$ 36
Total noncurrent derivative liabilities	$ 2	$ 79	$ 32	$ 113	$ (13)	100	$ —	$ 18	$ 1	$ 19	$ 17	36
PPAs [(b)]						75						93
Noncurrent derivative instruments						$ 175						$ 129

(a) Xcel Energy nets derivative instruments and related collateral in its consolidated balance sheet when supported by a legally enforceable master netting agreement and all derivative instruments and related collateral amounts were subject to master netting agreements as of Dec. 31, 2019 and 2018. At both Dec. 31, 2019 and 2018, derivative assets and liabilities included $32 million of obligations to return cash collateral. At Dec. 31, 2019 and 2018, derivative assets and liabilities included rights to reclaim cash collateral of $11 million and $15 million, respectively. Counterparty netting excludes settlement receivables and payables and non-derivative amounts that may be subject to the same master netting agreements.

(b) During 2006, Xcel Energy qualified these contracts under the normal purchase exception. Based on this qualification, the contracts are no longer adjusted to fair value and the previous carrying value of these contracts will be amortized over the remaining contract lives along with the offsetting regulatory assets and liabilities.

Changes in Level 3 commodity derivatives:

(Millions of Dollars)	Year Ended Dec. 31 2019	2018	2017
Balance at Jan. 1	$ 29	$ 35	$ 17
Purchases	44	59	82
Settlements	(64)	(59)	(97)
Net transactions recorded during the period:			
(Losses) gains recognized in earnings [(a)]	(8)	(1)	5
Net gains (losses) recognized as regulatory assets and liabilities	3	(5)	28
Balance at Dec. 31	$ 4	$ 29	$ 35

(a) Amounts relate to commodity derivatives held at the end of the period.

Xcel Energy recognizes transfers between levels as of the beginning of each period. There were no transfers of amounts between levels for derivative instruments for 2017 - 2019.

Fair Value of Long-Term Debt

As of Dec. 31, other financial instruments for which the carrying amount did not equal fair value:

(Millions of Dollars)	2019 Carrying Amount	2019 Fair Value	2018 Carrying Amount	2018 Fair Value
Long-term debt, including current portion	$ 18,109	$ 20,227	$ 16,209	$ 16,755

Fair value of Xcel Energy's long-term debt is estimated based on recent trades and observable spreads from benchmark interest rates for similar securities. Fair value estimates are based on information available to management as of Dec. 31, 2019 and 2018, and given the observability of the inputs, fair values presented for long-term debt were assigned as Level 2.

11. Benefit Plans and Other Postretirement Benefits

Pension and Postretirement Health Care Benefits

Xcel Energy has several noncontributory, defined benefit pension plans that cover almost all employees. Generally, benefits are based on a combination of years of service and average pay. Xcel Energy's policy is to fully fund into an external trust the actuarially determined pension costs subject to the limitations of applicable employee benefit and tax laws.

In addition to the qualified pension plans, Xcel Energy maintains a SERP and a nonqualified pension plan. The SERP is maintained for certain executives that were participants in the plan in 2008, when the SERP was closed to new participants.

The nonqualified pension plan provides benefits for compensation that is in excess of the limits applicable to the qualified pension plans, with distributions funded by Xcel Energy's consolidated operating cash flows.

Obligations of the SERP and nonqualified plan as of Dec. 31, 2019 and 2018 were $39 million and $33 million, respectively. Xcel Energy recognized net benefit cost for the SERP and nonqualified plans of $4 million in 2019 and in 2018.

Xcel Energy bases the investment-return assumption on expected long-term performance for each of the asset classes in its pension and postretirement health care portfolios. For pension assets, Xcel Energy considers the historical returns achieved by its asset portfolio over the past 20 years or longer period, as well as long-term projected return levels.

Pension cost determination assumes a forecasted mix of investment types over the long-term.

- Investment returns in 2019 were above the assumed level of 6.87%;
- Investment returns in 2018 were below the assumed level of 6.87%;
- Investment returns in 2017 were above the assumed level of 6.87%; and
- In 2020, expected investment-return assumption is 6.87%.

Pension plan and postretirement benefit assets are invested in a portfolio according to Xcel Energy's return, liquidity and diversification objectives to provide a source of funding for plan obligations and minimize contributions to the plan, within appropriate levels of risk. The principal mechanism for achieving these objectives is the asset allocation given the long-term risk, return, correlation and liquidity characteristics of each particular asset class. There were no significant concentrations of risk in any industry, index, or entity. Market volatility can impact even well-diversified portfolios and significantly affect the return levels achieved by the assets in any year.

State agencies also have issued guidelines to the funding of postretirement benefit costs. SPS is required to fund postretirement benefit costs for Texas and New Mexico amounts collected in rates. PSCo is required to fund postretirement benefit costs in irrevocable external trusts that are dedicated to the payment of these postretirement benefits. These assets are invested in a manner consistent with the investment strategy for the pension plan.

Xcel Energy's ongoing investment strategy is based on plan-specific investment recommendations that seek to minimize potential investment and interest rate risk as a plan's funded status increases over time. The investment recommendations result in a greater percentage of long-duration fixed income securities being allocated to specific plans having relatively higher funded status ratios and a greater percentage of growth assets being allocated to plans having relatively lower funded status ratios.

Plan Assets

For each of the fair value hierarchy levels, Xcel Energy's pension plan assets measured at fair value:

(Millions of Dollars)	Dec. 31, 2019 [(a)] Level 1	Level 2	Level 3	Measured at NAV	Total	Dec. 31, 2018 [(a)] Level 1	Level 2	Level 3	Measured at NAV	Total
Cash equivalents	$ 145	$ —	$ —	$ —	$ 145	$ 137	$ —	$ —	$ —	$ 137
Commingled funds	1,408	—	—	1,031	2,439	914	—	—	987	1,901
Debt securities	—	645	4	—	649	—	621	—	—	621
Equity securities	86	—	—	—	86	106	—	—	—	106
Other	(120)	5	—	(20)	(135)	2	5	—	(30)	(23)
Total	$ 1,519	$ 650	$ 4	$ 1,011	$ 3,184	$ 1,159	$ 626	$ —	$ 957	$ 2,742

(a) See Note 10 for further information regarding fair value measurement inputs and methods.

For each of the fair value hierarchy levels, Xcel Energy's postretirement benefit plan assets that were measured at fair value:

	Dec. 31, 2019 (a)					Dec. 31, 2018 (a)				
(Millions of Dollars)	Level 1	Level 2	Level 3	Measured at NAV	Total	Level 1	Level 2	Level 3	Measured at NAV	Total
Cash equivalents	$ 23	$ —	$ —	$ —	$ 23	$ 19	$ —	$ —	$ —	$ 19
Insurance contracts	—	51	—	—	51	—	45	—	—	45
Commingled funds	69	—	—	76	145	133	—	—	40	173
Debt securities	—	228	1	—	229	—	179	—	—	179
Other	—	1	—	—	1	—	1	—	—	1
Total	$ 92	$ 280	$ 1	$ 76	$ 449	$ 152	$ 225	$ —	$ 40	$ 417

(a) See Note 10 for further information on fair value measurement inputs and methods.

Immaterial assets were transferred in or out of Level 3 for 2019. No assets were transferred in or out of Level 3 for 2018.

Funded Status — Comparisons of the actuarially computed benefit obligation, changes in plan assets and funded status of the pension and postretirement health care plans for Xcel Energy are as follows:

	Pension Benefits		Postretirement Benefits	
(Millions of Dollars)	2019	2018	2019	2018
Change in Benefit Obligation:				
Obligation at Jan. 1	$ 3,477	$ 3,828	$ 542	$ 621
Service cost	86	94	2	2
Interest cost	145	133	22	22
Plan amendments	1	—	—	—
Actuarial loss (gain)	273	(224)	19	(62)
Plan participants' contributions	—	—	8	8
Medicare subsidy reimbursements	—	—	1	1
Benefit payments (a)	(281)	(354)	(47)	(50)
Obligation at Dec. 31	$ 3,701	$ 3,477	$ 547	$ 542
Change in Fair Value of Plan Assets:				
Fair value of plan assets at Jan. 1	$ 2,742	$ 3,088	$ 417	$ 461
Actual return on plan assets	568	(142)	56	(13)
Employer contributions	155	150	15	11
Plan participants' contributions	—	—	8	8
Benefit payments	(281)	(354)	(47)	(50)
Fair value of plan assets at Dec. 31	$ 3,184	$ 2,742	$ 449	$ 417
Funded status of plans at Dec. 31	$ (517)	$ (735)	$ (98)	$ (125)
Amounts recognized in the Consolidated Balance Sheet at Dec. 31:				
Noncurrent assets	$ —	$ —	$ 21	$ —
Current liabilities	—	—	(6)	(7)
Noncurrent liabilities	(517)	(735)	(113)	(118)
Net amounts recognized	$ (517)	$ (735)	$ (98)	$ (125)

(a) Includes approximately $20 million in 2019 and $198 million in 2018 of lump-sum benefit payments used in the determination of a settlement charge.

	Pension Benefits		Postretirement Benefits	
(Millions of Dollars)	2019	2018	2019	2018
Significant Assumptions Used to Measure Benefit Obligations:				
Discount rate for year-end valuation	3.49%	4.31%	3.47%	4.32%
Expected average long-term increase in compensation level	3.75	3.75	N/A	N/A
Mortality table	PRI-2012	RP-2014	PRI-2012	RP-2014
Health care costs trend rate — initial: Pre-65	N/A	N/A	6.00%	6.50%
Health care costs trend rate — initial: Post-65	N/A	N/A	5.10%	5.30%
Ultimate trend assumption — initial: Pre-65	N/A	N/A	4.50%	4.50%
Ultimate trend assumption — initial: Post-65	N/A	N/A	4.50%	4.50%
Years until ultimate trend is reached	N/A	N/A	3	4

Accumulated benefit obligation for the pension plan was $3,465 million and $3,275 million as of Dec. 31, 2019 and 2018, respectively.

Net Periodic Benefit Cost (Credit) — Net periodic benefit cost (credit), other than the service cost component, is included in other income in the consolidated statements of income.

Components of net periodic benefit cost (credit) and amounts recognized in other comprehensive income and regulatory assets and liabilities:

	Pension Benefits			Postretirement Benefits		
(Millions of Dollars)	**2019**	**2018**	**2017**	**2019**	**2018**	**2017**
Service cost	$ 86	$ 94	$ 94	$ 2	$ 2	$ 2
Interest cost	145	133	147	22	22	24
Expected return on plan assets	(203)	(209)	(209)	(21)	(26)	(25)
Amortization of prior service credit	(5)	(5)	(2)	(10)	(11)	(11)
Amortization of net loss	87	111	107	5	8	7
Settlement charge [a]	6	91	81	—	—	—
Net periodic pension cost (credit)	116	215	218	(2)	(5)	(3)
Costs not recognized due to effects of regulation	(1)	(75)	(79)	1	2	—
Net benefit cost (credit) recognized for financial reporting	$ 115	$ 140	$ 139	$ (1)	$ (3)	$ (3)
Significant Assumptions Used to Measure Costs:						
Discount rate	4.31%	3.63%	4.13%	4.32%	3.62%	4.13%
Expected average long-term increase in compensation level	3.75	3.75	3.75	—	—	—
Expected average long-term rate of return on assets	6.87	6.87	6.87	4.50	5.30	5.80

(a) A settlement charge is required when the amount of all lump-sum distributions during the year is greater than the sum of the service and interest cost components of the annual net periodic pension cost. In 2019 and 2018, as a result of lump-sum distributions during the 2019 and 2018 plan years, Xcel Energy recorded a total pension settlement charge of $6 million in 2019 and $91 million in 2018, the majority of which was not recognized due to the effects of regulation. A total of $1 million and $11 million was recorded in the consolidated statements of income in 2019 and 2018, respectively.

	Pension Benefits		Postretirement Benefits	
(Millions of Dollars)	**2019**	**2018**	**2019**	**2018**
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost:				
Net loss	$ 1,447	$ 1,633	$ 95	$ 116
Prior service credit	(15)	(20)	(23)	(33)
Total	$ 1,432	$ 1,613	$ 72	$ 83
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost Have Been Recorded as Follows Based Upon Expected Recovery in Rates:				
Current regulatory assets	$ 78	$ 94	$ —	$ —
Noncurrent regulatory assets	1,285	1,446	80	89
Current regulatory liabilities	—	—	(1)	(1)
Noncurrent regulatory liabilities	—	—	(12)	(10)
Deferred income taxes	18	19	1	1
Net-of-tax accumulated other comprehensive income	51	54	4	4
Total	$ 1,432	$ 1,613	$ 72	$ 83
Measurement date	Dec. 31, 2019	Dec. 31, 2018	Dec. 31, 2019	Dec. 31, 2018

Cash Flows — Funding requirements can be impacted by changes to actuarial assumptions, actual asset levels and other calculations prescribed by the requirements of income tax and other pension-related regulations. Required contributions were made in 2017 — 2020 to meet minimum funding requirements.

Voluntary and required pension funding contributions:

- $150 million in January 2020;
- $154 million in 2019;
- $150 million in 2018; and
- $162 million in 2017.

The postretirement health care plans have no funding requirements other than fulfilling benefit payment obligations, when claims are presented and approved. Additional cash funding requirements are prescribed by certain state and federal rate regulatory authorities.

Voluntary postretirement funding contributions:

- $10 million during 2020;
- $15 million during 2019;
- $11 million during 2018; and
- $20 million during 2017.

Targeted asset allocations:

	Pension Benefits		Postretirement Benefits	
	2019	2018	2019	2018
Domestic and international equity securities	37%	36%	15%	18%
Long-duration fixed income securities	30	30	—	—
Short-to-intermediate fixed income securities	14	17	72	70
Alternative investments	17	15	9	8
Cash	2	2	4	4
Total	100%	100%	100%	100%

Plan Amendments — The Xcel Energy Pension Plan and Xcel Energy Inc. Nonbargaining Pension Plan (South) were amended in 2017 to reduce supplemental benefits for non-bargaining participants as well as to allow the transfer of a portion of non-qualified pension obligations into the qualified plans.

In 2018, the PSCo postretirement plan was amended to add the 5% cash balance formula.

In 2019, the Pension Protection Act measurement concept was extended beyond 2019 for NSP bargaining terminations and retirements to Dec. 31, 2022.

There were no plan amendments made in 2019 which affected the postretirement benefit obligation.

Projected Benefit Payments

Xcel Energy's projected benefit payments:

(Millions of Dollars)	Projected Pension Benefit Payments	Gross Projected Postretirement Health Care Benefit Payments	Expected Medicare Part D Subsidies	Net Projected Postretirement Health Care Benefit Payments
2020	$ 278	$ 44	$ 2	$ 42
2021	263	43	2	41
2022	262	42	2	40
2023	260	41	2	39
2024	255	40	2	38
2025-2029	1,205	181	13	168

Defined Contribution Plans

Xcel Energy maintains 401(k) and other defined contribution plans that cover most employees. Total expense to these plans was approximately $39 million in 2019, $38 million in 2018 and $37 million in 2017.

Multiemployer Plans

NSP-Minnesota and NSP-Wisconsin each contribute to several union multiemployer pension and other postretirement benefit plans, none of which are individually significant. These plans provide pension and postretirement health care benefits to certain union employees who may perform services for multiple employers and do not participate in the NSP-Minnesota and NSP-Wisconsin sponsored pension and postretirement health care plans.

Contributing to these types of plans creates risk that differs from providing benefits under NSP-Minnesota and NSP-Wisconsin sponsored plans, in that if another participating employer ceases to contribute to a multiemployer plan, additional unfunded obligations may need to be funded over time by remaining participating employers.

12. Commitments and Contingencies

Legal

Xcel Energy is involved in various litigation matters that are being defended and handled in the ordinary course of business. Assessing whether a loss is probable or a reasonable possibility, and whether the loss or a range of loss is estimable, often involves complex judgments regarding future events. Management maintains accruals for losses that are probable of being incurred and subject to reasonable estimation.

Management may be unable to estimate an amount or range of a reasonably possible loss in certain situations, including when (1) the damages sought are indeterminate, (2) the proceedings are in the early stages, or (3) the matters involve novel or unsettled legal theories. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution of such matters, including a possible eventual loss. For current proceedings not specifically reported herein, management does not anticipate the ultimate liabilities, if any, arising from such current proceedings would have a material effect on Xcel Energy's financial statements. Unless otherwise required by GAAP, legal fees are expensed as incurred.

Gas Trading Litigation — e prime is a wholly owned subsidiary of Xcel Energy. e prime was in the business of natural gas trading and marketing but has not engaged in natural gas trading or marketing activities since 2003. Multiple lawsuits involving multiple plaintiffs seeking monetary damages were commenced against e prime and its affiliates, including Xcel Energy, between 2003 and 2009 alleging fraud and anticompetitive activities in conspiring to restrain the trade of natural gas and manipulate natural gas prices. Cases were all consolidated in the U.S. District Court in Nevada.

Two cases remain active which include an MDL matter consisting of a Colorado purported class (Breckenridge) and a Wisconsin purported class (Arandell Corp.).

Breckenridge/Colorado — In February 2019, the MDL panel remanded Breckenridge back to the U.S. District Court in Colorado.

Arandell Corp. — In February 2019, the case was remanded back to the U.S. District Court in Wisconsin.

Xcel Energy has concluded that a loss is remote for both remaining lawsuits.

Line Extension Disputes — In December 2015, the DRC filed a lawsuit seeking monetary damages in the Denver District Court, stating PSCo failed to award proper allowances and refunds for line extensions to new developments pursuant to the terms of electric and gas service agreements. The dispute involves claims by over fifty developers. In February 2018, the Colorado Supreme Court denied DRC's petition to appeal the Denver District Court's dismissal of the lawsuit, effectively terminating this litigation. However, in January 2018, DRC filed a new lawsuit in Boulder County District Court, asserting a single claim that PSCo was required to file its line extension agreements with the CPUC but failed to do so.

This claim is similar to the arguments previously raised by the DRC. PSCo filed a motion to dismiss this claim, which was granted in May 2018. The DRC subsequently filed an appeal to the Colorado Court of Appeals. In November 2019, the Colorado Court of Appeals issued an opinion affirming dismissal of the lawsuit based upon lack of subject matter jurisdiction. The Colorado Court of Appeals did not address the second issue based upon issue preclusion. Finally, the Colorado Court of Appeals remanded the case to the Boulder District Court to consider PSCo's request for an award of costs, which it concluded does not include attorneys' fees. The DRC did not file a petition for a Writ of Certiorari to the Colorado Supreme Court by the Dec. 26, 2019 deadline, effectively terminating this litigation.

Rate Matters

MEC Acquisition — In November 2018, NSP-Minnesota reached an agreement with Southern Power Company (a subsidiary of Southern Company) to purchase MEC, a 760 MW natural gas combined cycle facility, with capacity and energy historically sold to NSP-Minnesota under PPAs expiring in 2026 and 2039, for approximately $650 million.

In September 2019, the MPUC denied NSP-Minnesota's request to purchase MEC as a rate base asset. In January 2020, the MPUC approved Xcel Energy's plan to acquire MEC as a non-regulated investment and step into the terms of the existing PPAs with NSP-Minnesota. A newly formed non-regulated subsidiary of Xcel Energy completed the transaction to purchase MEC on Jan. 17, 2020.

Sherco — In NSP-Minnesota's 2013 fuel reconciliation filing, the MPUC made recovery of replacement power costs associated with the 2011 incident at its Sherco Unit 3 plant provisional and subject to further review following conclusion of litigation commenced by NSP-Minnesota, SMMPA (Co-owner of Sherco Unit 3) and insurance companies against GE.

In 2018, NSP-Minnesota and SMMPA reached a settlement with GE. NSP-Minnesota notified the MPUC of its proposal to refund the GE settlement proceeds back to customers through the FCA. The insurance providers continued their litigation against GE and the case went to trial.

In 2018, GE prevailed in the lawsuit with the insurance companies, however, the jury found comparable fault, finding that GE was 52% and NSP-Minnesota was 48% at fault. At that point in the litigation, NSP-Minnesota was no longer involved in the case and was not present to make arguments about its role in the event. The specific issue leading to the fault apportionment was also not before the jury and not relevant to the outcome of the trial.

In January 2019, the DOC recommended that NSP-Minnesota refund $20 million of previously recovered purchased power costs to its customers, based on the jury's apportionment of fault. The OAG recommended the MPUC withhold any decision until the underlying litigation by the insurance providers (currently under appeal) is concluded. The DOC subsequently filed comments agreeing with the OAG's recommendation to withhold a decision pending the outcome of any appeals. NSP-Minnesota filed reply comments arguing that the DOC recommendations are without merit and that it acted prudently in operating the plant and its settlement with GE was reasonable.

In March 2019, MPUC approved NSP-Minnesota's proposal to refund the GE settlement proceeds back to customers through the FCA. It also decided to withhold any decision as to NSP-Minnesota's prudence in connection with the incident at Sherco Unit 3 until after conclusion of the pending litigation between GE and NSP-Minnesota's insurers.

MISO ROE Complaints — In November 2013 and February 2015, customers filed complaints against MISO TOs including NSP-Minnesota and NSP-Wisconsin.

The first complaint argued for a reduction in the base ROE in MISO transmission formula rates from 12.38% to 9.15%, and removal of ROE adders (including those for RTO membership). The second complaint sought to reduce base ROE from 12.38% to 8.67%.

In September 2016, the FERC issued an order granting a 10.32% base ROE (10.82% with the RTO adder) effective for the first complaint period of Nov. 12, 2013 to Feb. 11, 2015 and subsequent to the date of the order. The D.C. Circuit subsequently vacated and remanded FERC Opinion No. 531, which had established the ROE methodology on which the September 2016 FERC order was based.

On March 21, 2019, FERC announced a NOI seeking public comments on whether, and if so how, to revise ROE policies in light of the D.C. Circuit Court decision. FERC also initiated a NOI on whether to revise its policies on incentives for electric transmission investments, including the RTO membership incentive. In November 2019, the FERC issued an order adopting a new ROE methodology and settling the MISO base ROE at 9.88% (10.38% with the RTO adder), effective Sept. 28, 2016 and for the Nov. 12, 2013 to Feb. 11, 2015 refund period. The FERC also dismissed the second complaint.

In December 2019, MISO TOs filed a request for rehearing. Customers also filed requests for rehearing claiming, among other points, that the FERC erred by dismissing the second complaint without refunds. Xcel Energy has recognized a liability for its best estimate of final refunds to customers. It is uncertain when the FERC will act on the requests for rehearing or any other pending matters related to the 2019 NOIs.

Texas Fuel Reconciliation — In December 2018, SPS filed an application with the PUCT for reconciliation of fuel costs for the period Jan. 1, 2016, through June 30, 2018, to determine whether all fuel costs incurred were eligible for recovery. In December 2019, the PUCT issued an order disallowing recovery of costs for Texas customers related to two specific solar PPAs. These PPAs were previously approved by the NMPRC as reasonable, necessary and economic. SPS recorded a total disallowance of approximately $6 million in December 2019.

SPP OATT Upgrade Costs — Under the SPP OATT, costs of transmission upgrades may be recovered from other SPP customers whose transmission service depends on capacity enabled by the upgrade. SPP had not been charging its customers for these upgrades, even though the SPP OATT had allowed SPP to do so since 2008. In 2016, the FERC granted SPP's request to recover previously unbilled charges and SPP subsequently billed SPS approximately $13 million.

In July 2018, SPS' appeal to the D.C. Circuit over the FERC rulings granting SPP the right to recover previously unbilled charges was remanded to the FERC. In February 2019, the FERC reversed its 2016 decision and ordered SPP to refund charges retroactively collected from its transmission customers, including SPS, related to periods before September 2015. In April 2019, several parties, including SPP, filed requests for a rehearing. Timing of a FERC response to rehearing requests is uncertain. Any refunds received by SPS are expected to be given back to SPS customers through future rates.

In October 2017, SPS filed a separate complaint against SPP asserting SPP assessed upgrade charges to SPS in violation of the SPP OATT. The FERC granted a rehearing for further consideration in May 2018. Timing of FERC action on the SPS rehearing is uncertain. If SPS' complaint results in additional charges or refunds, SPS will seek to recover or refund the amounts through future SPS customer rates.

Environmental

New and changing federal and state environmental mandates can create financial liabilities for Xcel Energy, which are normally recovered through the regulated rate process.

Site Remediation — Various federal and state environmental laws impose liability where hazardous substances or other regulated materials have been released to the environment. Xcel Energy Inc.'s subsidiaries may sometimes pay all or a portion of the cost to remediate sites where past activities of their predecessors or other parties have caused environmental contamination. Environmental contingencies could arise from various situations, including sites of former MGPs; and third-party sites, such as landfills, for which one or more of Xcel Energy Inc.'s subsidiaries are alleged to have sent wastes to that site.

MGP Sites

Ashland MGP Site — NSP-Wisconsin was named a responsible party for contamination at the Ashland/Northern States Power Lakefront Superfund Site (the Site) in Ashland, Wisconsin. Remediation was completed in 2019 and restoration activities are anticipated to be completed in 2020. Groundwater treatment activities will continue for many years.

The current cost estimate for remediation and restoration of the entire site is approximately $199 million. At Dec. 31, 2019 and 2018, NSP-Wisconsin had a total liability of $23 million and $27 million, respectively, for the entire site.

NSP-Wisconsin has deferred the unrecovered portion of the estimated Site remediation and restoration costs as a regulatory asset. The PSCW has authorized NSP-Wisconsin rate recovery for all remediation and restoration costs incurred at the Site. In its final December 2019 order approving 2020 and 2021 natural gas base rates, the PSCW authorized continued amortization of costs and application of a 3% carrying charge to the regulatory asset.

MGP, Landfill or Disposal Sites — PSCo is cooperating with the City of Denver on an environmental investigation of the Rice Yards Site in Denver, Colorado, which had various historic industrial uses by multiple parties, including railroad, maintenance shop, scrap metal yard, and MGP operations.

The area is being redeveloped into residential and commercial mixed uses, and PSCo is in discussions with the current property owner regarding legal claims related to the Rice Yards Site.

In addition, Xcel Energy is currently investigating or remediating 12 other MGP, landfill or other disposal sites across its service territories.

Xcel Energy has recognized its best estimate of costs/liabilities that will result from final resolution of these issues, however, the outcome and timing is unknown. In addition, there may be insurance recovery and/or recovery from other potentially responsible parties, offsetting a portion of costs incurred.

Environmental Requirements — Water and Waste

Coal Ash Regulation — Xcel Energy's operations are subject to federal and state laws that impose requirements for handling, storage, treatment and disposal of solid waste. Under the CCR Rule, utilities are required to complete groundwater sampling around their CCR landfills and surface impoundments. Currently, Xcel Energy has nine regulated ash units in operation.

Xcel Energy is conducting groundwater sampling and, where appropriate, initiating the assessment of corrective measures and evaluating whether corrective action is required at any CCR landfills or surface impoundments. In 2019, groundwater monitoring consistent with the CCR Rule was conducted. In NSP-Minnesota, no results above the groundwater protection standards in the rule were identified. In PSCo, statistically significant increase above background concentration was detected at four locations. Subsequently, assessment monitoring samples were collected, and PSCo is evaluating the results to determine whether corrective action is required. Until PSCo completes its assessment, it is uncertain what impact, if any, there will be on the operations, financial condition or cash flows.

In August 2018, the D.C. Circuit ruled that the EPA cannot allow utilities to continue to use unlined impoundments (including clay lined impoundments) for the storage or disposal of coal ash. In November 2019, the EPA proposed rules in response to this decision.

If finalized in their current form, these rules would require NSP-Minnesota to expedite closure plans for one impoundment at an estimated cost of $2 million and the construction of a new impoundment at the cost of $9 million.

In 2019, Xcel Energy initiated the construction of this new impoundment, an ash pond, expected to be in service in 2020. Upon placing the new ash pond in service, the existing ash pond will be taken out of service, and closure activities as prescribed by the CCR Rule and the facility's National Pollutant Discharge Elimination System permit will be initiated. In addition, the rules proposed by the EPA may require PSCo to expedite the closure of one coal ash impoundment.

Closure costs for existing impoundments are included in the calculation of the ARO liability. See Note 12 for further information.

Federal CWA WOTUS Rule — In 2015, the EPA and U.S. Army Corps of Engineers published a final rule that significantly broadened the scope of waters under the CWA that are subject to federal jurisdiction, referred to as "WOTUS". In 2019, the EPA repealed the 2015 rule and published a draft replacement rule. Until a final rule is issued, Xcel Energy cannot estimate potential impacts, but anticipates costs will be recoverable through regulatory mechanisms.

Federal CWA ELG — In 2015, the EPA issued a final ELG rule for power plants that discharge treated effluent to surface waters as well as utility-owned landfills that receive CCRs. In 2017, the EPA delayed the compliance date for flue gas desulfurization wastewater and bottom ash transport until November 2020. After 2020, Xcel Energy estimates that ELG compliance will cost approximately $12 million to complete. The EPA, however, is conducting a rulemaking process to revise certain effluent limitations and pretreatment standards, which may impact compliance costs. Xcel Energy anticipates these costs will be fully recoverable through regulatory mechanisms.

Federal CWA Section 316(b) — The federal CWA requires the EPA to regulate cooling water intake structures to assure that these structures reflect the best technology available for minimizing impingement and entrainment of aquatic species. Xcel Energy estimates the likely cost for complying with impingement and entrainment requirements is approximately $40 million, to be incurred between 2020 and 2028. Xcel Energy believes six NSP-Minnesota plants and two NSP-Wisconsin plants could be required by state regulators to make improvements to reduce impingement and entrainment. The exact total cost of the impingement and entrainment improvements is uncertain but could be up to approximately $198 million. Xcel Energy anticipates these costs will be fully recoverable through regulatory mechanisms.

Environmental Requirements — Air

Regional Haze Rules — The regional haze program requires SO_2, nitrogen oxide and particulate matter emission controls at power plants to reduce visibility impairment in national parks and wilderness areas. The program includes BART and reasonable further progress. The requirements of the first regional haze plans developed by Minnesota and Colorado have been approved and implemented. Texas' first regional haze plan has undergone federal review as described below.

BART Determination for Texas: The EPA has issued a revised final rule adopting a BART alternative Texas only SO_2 trading program that applies to all Harrington and Tolk units. Under the trading program, SPS expects the allowance allocations to be sufficient for SO_2 emissions. The anticipated costs of compliance are not expected to have a material impact; and SPS believes that compliance costs would be recoverable through regulatory mechanisms.

Several parties have challenged whether the final rule issued by the EPA should be considered to have met the requirements imposed in a Consent Decree entered by the United States District Court for the District of Columbia that established deadlines for the EPA to take final action on state regional haze plan submissions. The court has required status reports from the parties while the EPA works on the reconsideration rulemaking.

In December 2017, the National Parks Conservation Association, Sierra Club, and Environmental Defense Fund appealed the EPA's 2017 final BART rule to the Fifth Circuit and filed a petition for administrative reconsideration. In January 2018, the court granted SPS' motion to intervene in the Fifth Circuit litigation in support of the EPA's final rule. The court has held the litigation in abeyance while the EPA decided whether to reconsider the rule. In August 2018, the EPA started a reconsideration rulemaking, which was supplemented by an additional agency notice in November 2019. It is not known when the EPA will make a final decision on this proposal.

Reasonable Progress Rule: In 2016, the EPA adopted a final rule establishing a federal implementation plan for reasonable further progress under the regional haze program for the state of Texas. The rule imposes SO_2 emission limitations that would require the installation of dry scrubbers on Tolk Units 1 and 2, with compliance required by February 2021. Investment costs associated with dry scrubbers could be $600 million. SPS appealed the EPA's decision and obtained a stay of the final rule.

In March 2017, the Fifth Circuit remanded the rule to the EPA for reconsideration, leaving the stay in effect. In a future rulemaking, the EPA will address whether SO_2 emission reductions beyond those required in the BART alternative rule are needed at Tolk under the "reasonable progress" requirements. The EPA has not announced a schedule for acting on the remanded rule.

Implementation of the NAAQS for SO_2 — The EPA has designated all areas near SPS' generating plants as attaining the SO_2 NAAQS with an exception. The EPA issued final designations, which found the area near the SPS Harrington plant as "unclassifiable." The area near the Harrington plant is to be monitored for three years and a final designation is expected to be made by December 2020.

If the area near the Harrington plant is designated nonattainment in 2020, the TCEQ will need to develop an implementation plan, designed to achieve the NAAQS by 2025. The TCEQ could require additional SO_2 controls at Harrington as part of such a plan. Xcel Energy cannot evaluate the impacts until the final designation is made and any required state plans are developed.

Xcel Energy believes that should SO_2 control systems be required for a plant, compliance costs or the costs of alternative cost-effective generation will be recoverable through regulatory mechanisms and therefore does not expect a material impact on results of operations, financial condition or cash flows.

AROs — AROs have been recorded for Xcel Energy's assets. For nuclear assets, the ARO is associated with the decommissioning of NSP-Minnesota nuclear generating plants.

Aggregate fair value of NSP-Minnesota's legally restricted assets, for funding future nuclear decommissioning, was $2.4 billion and $2.1 billion for 2019 and 2018, respectively.

Xcel Energy's AROs were as follows:

(Millions of Dollars)	Jan. 1, 2019	Amounts Incurred (a)	Amounts Settled (b)	Accretion	Cash Flow Revisions (c)	Dec. 31, 2019
Electric						
Nuclear	$1,968	$ —	$ —	$ 100	$ —	$2,068
Steam, hydro and other production	177	—	(5)	8	22	202
Wind	119	26	—	7	(6)	146
Distribution	42	—	—	2	—	44
Miscellaneous	7	—	—	—	(7)	—
Natural gas						
Transmission and distribution	249	—	—	11	(24)	236
Miscellaneous	4	—	—	—	(1)	3
Common						
Miscellaneous	1	—	—	—	—	1
Non-utility						
Miscellaneous	1	—	—	—	—	1
Total liability	$2,568	$ 26	$ (5)	$ 128	$ (16)	$2,701

(a) Amounts incurred related to the wind farms placed in service in 2019 for NSP-Minnesota (Lake Benton and Foxtail) and SPS (Hale).

(b) Amounts settled related to asbestos abatement projects and closure of certain ash containment facilities.

(c) In 2019, AROs were revised for changes in timing and estimates of cash flows. Changes in gas transmission and distribution AROs were primarily related to increased gas line mileage and number of services, which were more than offset by decreased inflation rates. Changes in steam, hydro and other production AROs primarily related to the cost estimates to remediate ponds at production facilities. Changes in wind AROs were driven by new dismantling studies.

(Millions of Dollars)	Jan. 1, 2018	Amounts Incurred (a)	Amounts Settled (b)	Accretion	Cash Flow Revisions (c)	Dec. 31, 2018
Electric						
Nuclear	$1,874	$ —	$ —	$ 94	$ —	$ 1,968
Steam, hydro and other production	192	—	(14)	8	(9)	177
Wind	96	12	—	4	7	119
Distribution	21	—	—	1	20	42
Miscellaneous	5	—	—	—	2	7
Natural gas						
Transmission and distribution	282	—	—	13	(46)	249
Miscellaneous	4	—	—	—	—	4
Common						
Miscellaneous	1	—	—	—	—	1
Non-utility						
Miscellaneous	—	1	—	—	—	1
Total liability	$2,475	$ 13	$ (14)	$ 120	$ (26)	$ 2,568

(a) Amounts incurred related to the PSCo Rush Creek wind farm and Nicollet Projects community solar gardens, which were placed in service in 2018.

(b) Amounts settled related to asbestos abatement projects and closure of certain ash containment facilities.

(c) In 2018, AROs were revised for changes in timing and estimates of cash flows. Changes in gas transmission and distribution AROs were primarily related to increased gas line mileage and number of services, which were more than offset by increased discount rates. Changes in electric distribution AROs primarily related to increased labor costs.

Indeterminate AROs — Other plants or buildings may contain asbestos due to the age of many of Xcel Energy's facilities, but no confirmation or measurement of the cost of removal could be determined as of Dec. 31, 2019. Therefore, an ARO was not recorded for these facilities.

Removal Costs — Xcel Energy records a regulatory liability for the plant removal costs of its utility subsidiaries that are recovered currently in rates. Removal costs have accumulated based on varying rates as authorized by the appropriate regulatory entities. The utility subsidiaries have estimated the amount of removal costs accumulated through historic depreciation expense based on current factors used in the existing depreciation rates.

Accumulated balances by entity at Dec. 31:

(Millions of Dollars)	2019	2018
NSP-Minnesota	$ 520	$ 485
PSCo	351	344
SPS	175	188
NSP-Wisconsin	171	158
Total Xcel Energy	$ 1,217	$ 1,175

Nuclear Related

Nuclear Insurance — NSP-Minnesota's public liability for claims from any nuclear incident is limited to $13.9 billion under the Price-Anderson amendment to the Atomic Energy Act. NSP-Minnesota has secured $450 million of coverage for its public liability exposure with a pool of insurance companies. The remaining $13.5 billion of exposure is funded by the Secondary Financial Protection Program, available from assessments by the federal government.

NSP-Minnesota is subject to assessments of up to $138 million per reactor-incident for each of its three licensed reactors, for public liability arising from a nuclear incident at any licensed nuclear facility in the United States. The maximum funding requirement is $21 million per reactor-incident during any one year. Maximum assessments are subject to inflation adjustments by the NRC and state premium taxes. The NRC's last adjustment was effective November 2018.

NSP-Minnesota purchases insurance for property damage and site decontamination cleanup costs from NEIL and EMANI. The coverage limits are $2.7 billion for each of NSP-Minnesota's two nuclear plant sites. NEIL also provides business interruption insurance coverage up to $350 million, including the cost of replacement power during prolonged accidental outages of nuclear generating units. Premiums are expensed over the policy term.

All companies insured with NEIL are subject to retroactive premium adjustments if losses exceed accumulated reserve funds. Capital has been accumulated in the reserve funds of NEIL and EMANI to the extent that NSP-Minnesota would have no exposure for retroactive premium assessments in case of a single incident under the business interruption and the property damage insurance coverage.

NSP-Minnesota could be subject to annual maximum assessments of approximately $12 million for business interruption insurance and $35 million for property damage insurance if losses exceed accumulated reserve funds.

Nuclear Fuel Disposal — NSP-Minnesota is responsible for temporarily storing spent nuclear fuel from its nuclear plants. The DOE is responsible for permanently storing spent fuel from U.S. nuclear plants, but no such facility is yet available.

NSP-Minnesota owns temporary on-site storage facilities for spent fuel at its Monticello and PI nuclear plants, which consist of storage pools and dry cask facilities. The Monticello dry-cask storage facility currently stores all 30 of the authorized canisters. The PI dry-cask storage facility currently stores 44 of the 64 authorized casks. Monticello's future spent fuel will continue to be placed in its spent fuel pool. The decommissioning plan addresses the disposition of spent fuel at the end of the licensed life.

Regulatory Plant Decommissioning Recovery — Decommissioning activities for NSP-Minnesota's nuclear facilities are planned to begin at the end of each unit's operating license and be completed by 2091. NSP-Minnesota's current operating licenses allow continued use of its Monticello nuclear plant until 2030 and its PI nuclear plant until 2033 for Unit 1 and 2034 for Unit 2.

Future decommissioning costs of nuclear facilities are estimated through triennial periodic studies that assess the costs and timing of planned nuclear decommissioning activities for each unit.

Obligations for decommissioning are expected to be funded 100% by the external decommissioning trust fund. The cost study assumes the external decommissioning fund will earn an after-tax return between 5.23% and 6.30%. Realized and unrealized gains on fund investments are deferred as an offset of NSP-Minnesota's regulatory asset for nuclear decommissioning costs. Decommissioning costs are quantified in 2014 dollars. Escalation rates are 4.36% for plant removal activities and 3.36% for fuel management and site restoration activities.

NSP-Minnesota had $2.4 billion of assets held in external decommissioning trusts at Dec. 31, 2019. The following table summarizes the funded status of NSP-Minnesota's decommissioning obligation. Xcel Energy believes future decommissioning costs will continue to be recovered in customer rates. The following amounts were prepared on a regulatory basis and not directly recorded in the financial statements as an ARO.

	Regulatory Basis	
(Millions of Dollars)	2019	2018
Estimated decommissioning cost obligation from most recently approved study (in 2014 dollars)	$ 3,012	$ 3,012
Effect of escalating costs	688	539
Estimated decommissioning cost obligation (in current dollars)	3,700	3,551
Effect of escalating costs to payment date	7,505	7,654
Estimated future decommissioning costs (undiscounted)	11,205	11,205
Effect of discounting obligation (using average risk-free interest rate of 2.39% and 3.33% for 2019 and 2018, respectively)	(5,562)	(6,911)
Discounted decommissioning cost obligation	$ 5,643	$ 4,294
Assets held in external decommissioning trust	$ 2,440	$ 2,055
Underfunding of external decommissioning fund compared to the discounted decommissioning obligation	3,203	2,239

Calculations and data used by the regulator in approving NSP-Minnesota's rates are useful in assessing future cash flows. Regulatory basis information is a means to reconcile amounts previously provided to the MPUC and utilized for regulatory purposes to amounts used for financial reporting.

Reconciliation of the discounted decommissioning cost obligation - regulated basis to the ARO recorded in accordance with GAAP:

(Millions of Dollars)	2019	2018
Discounted decommissioning cost obligation - regulated basis	$ 5,643	$ 4,294
Differences in discount rate and market risk premium	(2,295)	(1,447)
O&M costs not included for GAAP	(1,280)	(879)
Nuclear production decommissioning ARO - GAAP	$ 2,068	$ 1,968

Decommissioning expenses recognized as a result of regulation:

(Millions of Dollars)	2019	2018	2017
Annual decommissioning recorded as depreciation expense: (a) (b)	$ 20	$ 20	$ 20

(a) Decommissioning expense does not include depreciation of the capitalized nuclear asset retirement costs.

(b) Decommissioning expenses in 2019, 2018 and 2017 include Minnesota's retail jurisdiction annual funding requirement of approximately $14 million.

The 2014 nuclear decommissioning filing, approved in 2015, was used for regulatory presentation in 2019, 2018 and 2017. The 2017 filing, effective Jan. 1, 2019, has been approved by the MPUC. In December 2019, the MPUC verbally approved for NSP-Minnesota to delay any increase to the annual funding requirement until 2021.

Leases

Xcel Energy evaluates contracts that may contain leases, including PPAs and arrangements for the use of office space and other facilities, vehicles and equipment. Under ASC Topic 842, adopted by Xcel Energy on Jan. 1, 2019, a contract contains a lease if it conveys the exclusive right to control the use of a specific asset. A contract determined to contain a lease is evaluated further to determine if the arrangement is a finance lease.

ROU assets represent Xcel Energy's rights to use leased assets. Starting in 2019, the present value of future operating lease payments are recognized in other current liabilities and noncurrent operating lease liabilities. These amounts, adjusted for any prepayments or incentives, are recognized as operating lease ROU assets.

Most of Xcel Energy's leases do not contain a readily determinable discount rate. Therefore, the present value of future lease payments is generally calculated using the applicable Xcel Energy subsidiary's estimated incremental borrowing rate (weighted-average of 4.1%). Xcel Energy has elected the practical expedient under which non-lease components, such as asset maintenance costs included in payments, are not deducted from minimum lease payments for the purposes of lease accounting and disclosure.

Leases with an initial term of 12 months or less are classified as short-term leases and are not recognized on the consolidated balance sheet.

Operating lease ROU assets:

(Millions of Dollars)	Dec. 31, 2019
PPAs	$ 1,642
Other	201
Gross operating lease ROU assets	1,843
Accumulated amortization	(171)
Net operating lease ROU assets	$ 1,672

In 2019, ROU assets for finance leases are included in other noncurrent assets, and the present value of future finance lease payments is included in other current liabilities and other noncurrent liabilities. Prior to 2019, finance leases were included in property, plant and equipment, the current portion of long-term debt and long-term debt.

Xcel Energy's most significant finance lease activities are related to WYCO, a joint venture with CIG, to develop and lease natural gas pipeline, storage and compression facilities. Xcel Energy Inc. has a 50% ownership interest in WYCO. WYCO leases its facilities to CIG, and CIG operates the facilities, providing natural gas storage and transportation services to PSCo under separate service agreements.

PSCo accounts for its Totem natural gas storage service and Front Range pipeline arrangements with CIG and WYCO, respectively, as finance leases. Xcel Energy Inc. eliminates 50% of the finance lease obligation related to WYCO in the consolidated balance sheet along with an equal amount of Xcel Energy Inc.'s equity investment in WYCO.

Finance lease ROU assets:

(Millions of Dollars)	Dec. 31, 2019	Dec. 31, 2018
Gas storage facilities	$ 201	$ 201
Gas pipeline	21	21
Gross finance lease ROU assets	222	222
Accumulated amortization	(83)	(77)
Net finance lease ROU assets	$ 139	$ 145

Components of lease expense:

(Millions of Dollars)	2019	2018	2017
Operating leases			
PPA capacity payments	$ 221	$ 210	$ 210
Other operating leases (a)	34	38	36
Total operating lease expense (b)	$ 255	$ 248	$ 246
Finance leases			
Amortization of ROU assets	$ 6	$ 6	$ 5
Interest expense on lease liability	19	19	20
Total finance lease expense	$ 25	$ 25	$ 25

(a) Includes short-term lease expense of $5 million for 2019, 2018 and 2017.

(b) PPA capacity payments are included in electric fuel and purchased power on the consolidated statements of income. Expense for other operating leases is included in O&M expense and electric fuel and purchased power.

Commitments under operating and finance leases as of Dec. 31, 2019:

(Millions of Dollars)	PPA (a) (b) Operating Leases	Other Operating Leases	Total Operating Leases	Finance Leases (c)
2020	$ 236	$ 26	$ 262	$ 14
2021	238	29	267	14
2022	225	28	253	12
2023	214	25	239	12
2024	208	22	230	12
Thereafter	750	115	865	207
Total minimum obligation	1,871	245	2,116	271
Interest component of obligation	(321)	(52)	(373)	(190)
Present value of minimum obligation	$ 1,550	193	1,743	81
Less current portion			(194)	(4)
Noncurrent operating and finance lease liabilities			$ 1,549	$ 77
Weighted-average remaining lease term in years			9.3	37.0

(a) Amounts do not include PPAs accounted for as executory contracts and/or contingent payments, such as energy payments on renewable PPAs.

(b) PPA operating leases contractually expire at various dates through 2033.

(c) Excludes certain amounts related to Xcel Energy's 50% ownership interest in WYCO.

Operating lease liabilities at Dec. 31, 2019 include a present value of approximately $400 million for MEC PPA capacity payments. In 2020, these operating lease liabilities and related ROU assets will be eliminated from Xcel Energy's consolidated balance sheet following the completed January 2020 purchase of MEC by a newly formed non-regulated subsidiary of Xcel Energy.

Commitments under operating and finance leases as of Dec. 31, 2018:

(Millions of Dollars)	PPA [a] [b] Operating Leases	Other Operating Leases	Total Operating Leases	Finance Leases [c]
2019	$ 207	$ 32	$ 239	$ 14
2020	208	26	234	14
2021	210	25	235	14
2022	197	24	221	12
2023	186	22	208	12
Thereafter	883	154	1,037	220
Total minimum obligation				286
Interest component of obligation				(201)
Present value of minimum obligation				$ 85

(a) Amounts do not include PPAs accounted for as executory contracts and/or contingent payments, such as energy payments on renewable PPAs.

(b) PPA operating leases contractually expire at various dates through 2033.

(c) Excludes certain amounts related to Xcel Energy's 50% ownership interest in WYCO.

PPAs and Fuel Contracts

Non-Lease PPAs — NSP Minnesota, PSCo and SPS have entered into PPAs with other utilities and energy suppliers with various expiration dates through 2034 for purchased power to meet system load and energy requirements, operating reserve obligations and as part of wholesale and commodity trading activities. In general, these agreements provide for energy payments, based on actual energy delivered and capacity payments. Certain PPAs accounted for as executory contracts contain minimum energy purchase commitments, and total energy payments on those contracts were $102 million, $105 million and $100 million in 2019, 2018 and 2017, respectively.

Included in electric fuel and purchased power expenses for PPAs accounted for as executory contracts were payments for capacity of $86 million, $131 million and $168 million in 2019, 2018 and 2017, respectively.

Capacity and energy payments are contingent on the IPPs meeting contract obligations, including plant availability requirements. Certain contractual payments are adjusted based on market indices. The effects of price adjustments on financial results are mitigated through purchased energy cost recovery mechanisms.

At Dec. 31, 2019, the estimated future payments for capacity and energy that the utility subsidiaries of Xcel Energy are obligated to purchase pursuant to these executory contracts, subject to availability, were as follows:

(Millions of Dollars)	Capacity	Energy [a]
2020	$ 70	$ 110
2021	78	157
2022	77	173
2023	79	177
2024	74	182
Thereafter	56	146
Total	$ 434	$ 945

(a) Excludes contingent energy payments for renewable energy PPAs.

Fuel Contracts — Xcel Energy has entered into various long-term commitments for the purchase and delivery of a significant portion of its coal, nuclear fuel and natural gas requirements. These contracts expire between 2020 and 2060. Xcel Energy is required to pay additional amounts depending on actual quantities shipped under these agreements.

Estimated minimum purchases under these contracts as of Dec. 31, 2019:

(Millions of Dollars)	Coal	Nuclear fuel	Natural gas supply	Natural gas supply and transportation
2020	$ 430	$ 54	$ 343	$ 295
2021	222	103	254	283
2022	135	85	104	269
2023	58	103	53	198
2024	24	74	3	153
Thereafter	74	275	—	860
Total	$ 943	$ 694	$ 757	$ 2,058

VIEs

PPAs — Under certain PPAs, NSP-Minnesota, PSCo and SPS purchase power from IPPs for which the utility subsidiaries are required to reimburse fuel costs, or to participate in tolling arrangements under which the utility subsidiaries procure the natural gas required to produce the energy that they purchase. Xcel Energy has determined that certain IPPs are VIEs. Xcel Energy is not subject to risk of loss from the operations of these entities, and no significant financial support is required other than contractual payments for energy and capacity.

In addition, certain solar PPAs provide an option to purchase emission allowances or sharing provisions related to production credits generated by the solar facility under contract. These specific PPAs create a variable interest in the IPP.

Xcel Energy evaluated each of these VIEs for possible consolidation, including review of qualitative factors such as the length and terms of the contract, control over O&M, control over dispatch of electricity, historical and estimated future fuel and electricity prices, and financing activities. Xcel Energy concluded that these entities are not required to be consolidated in its consolidated financial statements because it does not have the power to direct the activities that most significantly impact the entities' economic performance.

The utility subsidiaries had approximately 3,986 MW and 3,770 MW of capacity under long-term PPAs at Dec. 31, 2019 and 2018, respectively, with entities that have been determined to be VIEs. Agreements have expiration dates through 2041.

Fuel Contracts — SPS purchases all of its coal requirements for its Harrington and Tolk plants from TUCO Inc. under contracts that will expire in December 2022. TUCO arranges for the purchase, receiving, transporting, unloading, handling, crushing, weighing and delivery of coal to meet SPS' requirements. TUCO is responsible for negotiating and administering contracts with coal suppliers, transporters and handlers.

SPS has not provided any significant financial support to TUCO, other than contractual payments for delivered coal. However, the fuel contracts create a variable interest in TUCO due to SPS' reimbursement of fuel procurement costs.

SPS has determined that TUCO is a VIE, however it has concluded that SPS is not the primary beneficiary of TUCO because it does not have the power to direct the activities that most significantly impact TUCO's economic performance.

Low-Income Housing Limited Partnerships — Eloigne and NSP-Wisconsin have entered into limited partnerships for the construction and operation of affordable rental housing developments which qualify for low-income housing tax credits. Xcel Energy Inc. has determined Eloigne and NSP-Wisconsin's low-income housing partnerships to be VIEs primarily due to contractual arrangements within each limited partnership that establish sharing of ongoing voting control and profits and losses that does not align with the partners' proportional equity ownership.

Eloigne and NSP-Wisconsin have the power to direct the activities that most significantly impact these entities' economic performance. Therefore, Xcel Energy Inc. consolidates these limited partnerships in its consolidated financial statements. Xcel Energy's risk of loss for these partnerships is limited to its capital contributions, adjusted for any distributions and its share of undistributed profits and losses; no significant additional financial support has been, or is required to be, provided to the limited partnerships by Eloigne or NSP-Wisconsin.

Amounts reflected in Xcel Energy's consolidated balance sheets for the Eloigne and NSP-Wisconsin low-income housing limited partnerships:

(Millions of Dollars)	Dec. 31, 2019	Dec. 31, 2018
Current assets	$ 7	$ 5
Property, plant and equipment, net	41	42
Other noncurrent assets	1	1
Total assets	$ 49	$ 48
Current liabilities	$ 8	$ 7
Mortgages and other long-term debt payable	26	26
Other noncurrent liabilities	—	—
Total liabilities	$ 34	$ 33

Other

Technology Agreements — Xcel Energy has a contract that extends through December 2022 with IBM for information technology services. The contract is cancelable at Xcel Energy's option, although Xcel Energy would be obligated to pay 50% of the contract value for early termination. Xcel Energy capitalized or expensed $46 million, $81 million and $98 million associated with the IBM contract in 2019, 2018 and 2017, respectively.

Xcel Energy's contract with Accenture for information technology services extends through December 2020. The contract is cancelable at Xcel Energy's option, although there are financial penalties for early termination. Xcel Energy capitalized or expensed $52 million, $46 million and $16 million associated with the Accenture contract in 2019, 2018 and 2017, respectively.

During 2019, Xcel Energy executed a contract with Cognizant for information technology services which extends through 2022. The contract is cancelable at Xcel Energy's option, although there are financial penalties for early termination. Xcel Energy capitalized or expensed $3 million associated with the Cognizant contract in 2019.

Committed minimum payments under these obligations:

(Millions of Dollars)	IBM Agreement	Accenture Agreement	Cognizant Agreement
2020	$ 15	$ 11	$ 9
2021	15	—	7
2022	6	—	3
2023	—	—	—
2024	—	—	—
Thereafter	—	—	—

Guarantees and Bond Indemnifications — Xcel Energy Inc. and its subsidiaries provide guarantees and bond indemnities, which guarantee payment or performance. Xcel Energy Inc.'s exposure is based upon the net liability under the specified agreements or transactions. Most of the guarantees and bond indemnities issued by Xcel Energy Inc. and its subsidiaries have a stated maximum amount. As of Dec. 31, 2019 and 2018, Xcel Energy Inc. and its subsidiaries had no assets held as collateral related to their guarantees, bond indemnities and indemnification agreements.

Guarantees and bond indemnities issued and outstanding for Xcel Energy were $62 million and $69 million as of Dec. 31, 2019 and 2018.

13. Other Comprehensive Income

Changes in accumulated other comprehensive loss, net of tax, for the years ended Dec. 31:

	2019		
(Millions of Dollars)	Gains and Losses on Cash Flow Hedges	Defined Benefit Pension and Postretirement Items	Total
Accumulated other comprehensive loss at Jan. 1	$ (60)	$ (64)	$ (124)
Other comprehensive loss before reclassifications (net of taxes of $(8) and $0, respectively)	(23)	—	(23)
Losses reclassified from net accumulated other comprehensive loss:			
Interest rate derivatives (net of taxes of $1 and $0, respectively)	3 (a)	—	3
Amortization of net actuarial loss (net of taxes of $0 and $1, respectively)	—	3 (b)	3
Net current period other comprehensive (loss) income	(20)	3	(17)
Accumulated other comprehensive loss at Dec. 31	$ (80)	$ (61)	$ (141)

(a) Included in interest charges.

(b) Included in the computation of net periodic pension and postretirement benefit costs. See Note 11 for further information.

	2018		
(Millions of Dollars)	Gains and Losses on Cash Flow Hedges	Defined Benefit Pension and Postretirement Items	Total
Accumulated other comprehensive loss at Jan. 1	$ (58)	$ (67)	$ (125)
Other comprehensive loss before reclassifications (net of taxes of $(2) and $(2), respectively)	(5)	(6)	(11)
Losses reclassified from net accumulated other comprehensive loss:			
Interest rate derivatives (net of taxes of $1 and $0, respectively)	3 (a)	—	3
Amortization of net actuarial loss (net of taxes of $0 and $3, respectively)	—	9 (b)	9
Net current period other comprehensive (loss) income	(2)	3	1
Accumulated other comprehensive loss at Dec. 31	$ (60)	$ (64)	$ (124)

(a) Included in interest charges.

(b) Included in the computation of net periodic pension and postretirement benefit costs. See Note 11 for further information.

14. Segments and Related Information

Xcel Energy evaluates performance by each utility subsidiary based on profit or loss generated from the product or service provided, including the regulated electric utility operating results of NSP-Minnesota, NSP-Wisconsin, PSCo and SPS, as well as the regulated natural gas utility operating results of NSP-Minnesota, NSP-Wisconsin and PSCo. These segments are managed separately because the revenue streams are dependent upon regulated rate recovery, which is separately determined for each segment.

Xcel Energy has the following reportable segments:

- *Regulated Electric* - The regulated electric utility segment generates, transmits and distributes electricity in Minnesota, Wisconsin, Michigan, North Dakota, South Dakota, Colorado, Texas and New Mexico. In addition, this segment includes sales for resale and provides wholesale transmission service to various entities in the United States. The regulated electric utility segment also includes wholesale commodity and trading operations; and
- *Regulated Natural Gas* - The regulated natural gas utility segment transports, stores and distributes natural gas primarily in portions of Minnesota, Wisconsin, North Dakota, Michigan and Colorado.

Xcel Energy presents Other, which includes operating segments, with revenues below the necessary quantitative thresholds. Those operating segments primarily include steam revenue, appliance repair services, non-utility real estate activities, revenues associated with processing solid waste into refuse-derived fuel and investments in rental housing projects that qualify for low-income housing tax credits.

Xcel Energy had equity investments in unconsolidated subsidiaries of $155 million and $141 million as of Dec. 31, 2019 and 2018, respectively, included in the natural gas utility and all other segments.

Asset and capital expenditure information is not provided for Xcel Energy's reportable segments. As an integrated electric and natural gas utility, Xcel Energy operates significant assets that are not dedicated to a specific business segment. Reporting assets and capital expenditures by business segment would require arbitrary and potentially misleading allocations, which may not necessarily reflect the assets that would be required for the operation of the business segments on a stand-alone basis.

Certain costs, such as common depreciation, common O&M expenses and interest expense are allocated based on cost causation allocators across each segment. In addition, a general allocator is used for certain general and administrative expenses, including office supplies, rent, property insurance and general advertising.

Xcel Energy's segment information:

(Millions of Dollars)	2019	2018	2017
Regulated Electric			
Operating revenues from external customers	$ 9,575	$ 9,719	$ 9,676
Intersegment revenue	1	1	2
Total revenues	$ 9,576	$ 9,720	$ 9,678
Depreciation and amortization	1,535	1,421	1,298
Interest charges and financing costs	500	449	449
Income tax expense	125	187	528
Net income	1,288	1,177	1,066
Regulated Natural Gas			
Operating revenues from external customers	$ 1,868	$ 1,739	$ 1,650
Intersegment revenue	2	2	1
Total revenues	$ 1,870	$ 1,741	$ 1,651
Depreciation and amortization	219	212	174
Interest charges and financing costs	69	61	57
Income tax expense	48	28	23
Net income	195	187	182
Other			
Total operating revenue	$ 86	$ 79	$ 78
Depreciation and amortization	11	9	7
Interest charges and financing costs	167	142	122
Income tax (benefit)	(45)	(34)	(9)
Net (loss)	(111)	(103)	(100)
Consolidated Total			
Total revenue	$ 11,532	$ 11,540	$ 11,407
Reconciling eliminations	(3)	(3)	(3)
Consolidated total revenue	$ 11,529	$ 11,537	$ 11,404
Depreciation and amortization	1,765	1,642	1,479
Interest charges and financing costs	736	652	628
Income tax expense	128	181	542
Net income	1,372	1,261	1,148

15. Summarized Quarterly Financial Data (Unaudited)

	Quarter Ended			
(Amounts in millions, except per share data)	March 31, 2019	June 30, 2019	Sept. 30, 2019	Dec. 31, 2019
Operating revenues	$ 3,141	$ 2,577	$ 3,013	$ 2,798
Operating income	486	410	758	450
Net income	315	238	527	292
EPS total — basic	$ 0.61	$ 0.46	$ 1.02	$ 0.56
EPS total — diluted	0.61	0.46	1.01	0.56
Cash dividends declared per common share	0.405	0.405	0.405	0.405

	Quarter Ended			
(Amounts in millions, except per share data)	March 31, 2018	June 30, 2018	Sept. 30, 2018	Dec. 31, 2018
Operating revenues	$ 2,951	$ 2,658	$ 3,048	$ 2,880
Operating income [(a)]	480	450	696	339
Net income	291	265	491	214
EPS total — basic	$ 0.57	$ 0.52	$ 0.96	$ 0.42
EPS total — diluted	0.57	0.52	0.96	0.42
Cash dividends declared per common share	0.380	0.380	0.380	0.380

(a) In 2018, Xcel Energy implemented ASU No. 2017-07 related to net periodic benefit cost, which resulted in retrospective reclassification of pension costs from O&M expense to other income.

ITEM 9 — CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A — CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

Xcel Energy maintains a set of disclosure controls and procedures designed to ensure that information required to be disclosed in reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized, and reported within the time periods specified in SEC rules and forms. In addition, the disclosure controls and procedures ensure that information required to be disclosed is accumulated and communicated to management, including the CEO and CFO, allowing timely decisions regarding required disclosure. As of Dec. 31, 2019, based on an evaluation carried out under the supervision and with the participation of Xcel Energy's management, including the CEO and CFO, of the effectiveness of its disclosure controls and procedures, the CEO and CFO have concluded that Xcel Energy's disclosure controls and procedures were effective.

Internal Control Over Financial Reporting

No changes in Xcel Energy's internal control over financial reporting occurred during the most recent fiscal quarter that materially affected, or are reasonably likely to materially affect, Xcel Energy's internal control over financial reporting. Xcel Energy maintains internal control over financial reporting to provide reasonable assurance regarding the reliability of the financial reporting. Xcel Energy has evaluated and documented its controls in process activities, general computer activities, and on an entity-wide level.

During the year and in preparation for issuing its report for the year ended Dec. 31, 2019 on internal controls under section 404 of the Sarbanes-Oxley Act of 2002, Xcel Energy conducted testing and monitoring of its internal control over financial reporting. Based on the control evaluation, testing and remediation performed, Xcel Energy did not identify any material control weaknesses, as defined under the standards and rules issued by the Public Company Accounting Oversight Board, as approved by the SEC and as indicated in Xcel Energy's Management Report on Internal Controls over Financial Reporting, which is contained in Item 8 herein.

ITEM 9B — OTHER INFORMATION

None.

PART III

ITEM 10 — DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information required under this Item with respect to Directors and Corporate Governance is set forth in Xcel Energy Inc.'s Proxy Statement for its 2020 Annual Meeting of Shareholders, which is expected to occur on April 6, 2020, incorporated by reference. Information with respect to Executive Officers is included in Item 1 to this report.

ITEM 11 — EXECUTIVE COMPENSATION

Information required under this Item is set forth in Xcel Energy Inc.'s Proxy Statement for its 2020 Annual Meeting of Shareholders, which is incorporated by reference.

ITEM 12 — SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Information required under this Item is contained in Xcel Energy Inc.'s Proxy Statement for its 2020 Annual Meeting of Shareholders, which is incorporated by reference.

ITEM 13 — CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Information required under this Item is contained in Xcel Energy Inc.'s Proxy Statement for its 2020 Annual Meeting of Shareholders, which is incorporated by reference.

ITEM 14 — PRINCIPAL ACCOUNTANT FEES AND SERVICES

Information required under this Item is contained in Xcel Energy Inc.'s definitive Proxy Statement for its 2020 Annual Meeting of Shareholders, which is incorporated by reference.

PART IV

ITEM 15 — EXHIBITS, FINANCIAL STATEMENT SCHEDULES

1	Consolidated Financial Statements
	Management Report on Internal Controls Over Financial Reporting — For the year ended Dec. 31, 2019.
	Report of Independent Registered Public Accounting Firm — Financial Statements
	Report of Independent Registered Public Accounting Firm — Internal Controls Over Financial Reporting
	Consolidated Statements of Income — For the three years ended Dec. 31, 2019, 2018, and 2017.
	Consolidated Statements of Comprehensive Income — For the three years ended Dec. 31, 2019, 2018, and 2017.
	Consolidated Statements of Cash Flows — For the three years ended Dec. 31, 2019, 2018, and 2017.
	Consolidated Balance Sheets — As of Dec. 31, 2019 and 2018.
	Consolidated Statements of Common Stockholders' Equity — For the three years ended Dec. 31, 2019, 2018, and 2017.
2	Schedule I — Condensed Financial Information of Registrant.
	Schedule II — Valuation and Qualifying Accounts and Reserves for the years ended Dec. 31, 2019, 2018 and 2017.
3	Exhibits
*	Indicates incorporation by reference
+	Executive Compensation Arrangements and Benefit Plans Covering Executive Officers and Directors

Xcel Energy Inc.

Exhibit Number	Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
3.01*	Amended and Restated Articles of Incorporation of Xcel Energy Inc.	Xcel Energy Inc Form 8-K dated May 16, 2012	001-03034	3.01
3.02*	Bylaws of Xcel Energy Inc.	Xcel Energy Inc Form 8-K dated Feb. 17, 2016	001-03034	3.01
4.01	Description of Securities			
4.02*	Indenture dated Dec. 1, 2000 between Xcel Energy Inc. and Wells Fargo Bank Minnesota, National Association, as Trustee	Xcel Energy Inc. Form 8-K dated Dec. 14, 2000	001-03034	4.01
4.03*	Supplemental Indenture No. 3 dated June 1, 2006 between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee	Xcel Energy Inc. Form 8-K dated June 6, 2006	001-03034	4.01
4.04*	Junior Subordinated Indenture, dated as of Jan. 1, 2008, by and between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee	Xcel Energy Inc. Form 8-K dated Jan. 16, 2008	001-03034	4.01
4.05*	Replacement Capital Covenant, dated Jan. 16, 2008	Xcel Energy Inc. Form 8-K dated Jan. 16, 2008	001-03034	4.03
4.06*	Supplemental Indenture dated as of May 1, 2010 between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee	Xcel Energy Inc. Form 8-K dated May 10, 2010	001-03034	4.01
4.07*	Supplemental Indenture No. 6, dated as of Sept. 1, 2011 between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee	Xcel Energy Inc. Form 8-K dated Sept. 12, 2011	001-03034	4.01
4.08*	Supplemental Indenture No. 8, dated as of June 1, 2015 between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee	Xcel Energy Inc. Form 8-K dated June 1, 2015	001-03034	4.01
4.09*	Supplemental Indenture No. 9, dated as of March 1, 2016, by and between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee	Xcel Energy Inc. Form 8-K dated March 8, 2016	001-03034	4.02
4.10*	Supplemental Indenture No. 10, dated as of Dec. 1, 2016, by and between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee	Xcel Energy Inc. Form 8-K dated Dec. 1, 2016	001-03034	4.01
4.11*	Supplemental Indenture No. 11, dated as of June 25, 2018, by and between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee	Xcel Energy Inc. Form 8-K dated June 25, 2018	001-03034	4.01
4.12*	Supplemental Indenture No. 12, dated as of Nov. 7, 2019 by and between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee, creating 2.60% Senior Notes, Series Due 2029 and 3.50% Senior Notes, Series due 2049	Xcel Energy Inc. Form 8-K dated Nov. 7, 2019	001-03034	4.01
10.01*	Xcel Energy Inc. Nonqualified Pension Plan (2009 Restatement)	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2008	001-03034	10.02
10.02*+	Xcel Energy Senior Executive Severance and Change-in-Control Policy (2009 Restatement)	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2008	001-03034	10.05
10.03*+	Xcel Energy Inc. Non-Employee Directors Deferred Compensation Plan as amended and restated Jan. 1, 2009	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2008	001-03034	10.08
10.04*+	Form of Services Agreement between Xcel Energy Services Inc. and utility companies	Xcel Energy Inc. Form U5B dated Nov. 16, 2000	001-03034	H-1
10.05*+	Xcel Energy Inc. Supplemental Executive Retirement Plan as amended and restated Jan. 1, 2009	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2008	001-03034	10.17
10.06*+	First Amendment to Exhibit 10.02 dated Aug. 26, 2009	Xcel Energy Inc. Form 10-Q for the quarter ended Sept. 30, 2009	001-03034	10.06

10.07*+	Xcel Energy Inc. Executive Annual Incentive Award Plan Form of Restricted Stock Agreement	Xcel Energy Inc. Form 10-Q for the quarter ended Sept. 30, 2009	001-03034	10.08
10.08*+	Xcel Energy Inc. Executive Annual Incentive Plan (as amended and restated effective Feb. 17, 2010)	Xcel Energy Inc. Definitive Proxy Statement dated April 6, 2010	001-03034	Appendix A
10.09*+	Stock Equivalent Plan for Non-Employee Directors of Xcel Energy Inc. as amended and restated effective Feb. 23, 2011	Xcel Energy Inc. Definitive Proxy Statement dated April 5, 2011	001-03034	Appendix A
10.10*+	Xcel Energy Inc. Nonqualified Deferred Compensation Plan (2009 Restatement)	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2008	001-03034	10.07
10.11*+	First Amendment to Exhibit 10.10 effective Nov. 29, 2011	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2011	001-03034	10.17
10.12*+	Second Amendment to Exhibit 10.02 dated Oct. 26, 2011	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2011	001-03034	10.18
10.13*+	First Amendment to Exhibit 10.08 dated Feb. 20, 2013	Xcel Energy Inc. Form 10-Q for the quarter ended March 31, 2013	001-03034	10.01
10.14*+	Fourth Amendment to Exhibit 10.02 dated Feb. 20, 2013	Xcel Energy Inc. Form 10-Q for the quarter ended March 31, 2013	001-03034	10.02
10.15*+	Second Amendment to Exhibit 10.10 dated May 21, 2013	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2013	001-03034	10.22
10.16*+	Stock Equivalent Program for Non-Employee Directors of Xcel Energy Inc. under the Xcel Energy Inc. 2015 Omnibus Incentive Plan	Xcel Energy Inc. Form 8-K dated May 20, 2015	001-03034	10.02
10.17*+	Fifth Amendment Exhibit 10.02 dated May 3, 2016	Xcel Energy Inc. Form 10-Q for the quarter ended June 30, 2016	001-03034	10.01
10.18*+	Third Amendment to Exhibit 10.10 dated Sept. 30, 2016	Xcel Energy Inc. Form 10-Q for the quarter ended Sept. 30, 2016	001-03034	10.01
10.19*+	Fourth Amendment to Exhibit 10.10 dated Oct. 23, 2017	Xcel Energy Inc. Form 10-Q for the quarter ended Sept. 30, 2017	001-03034	10.1
10.20*+	Sixth Amendment to Exhibit 10.02 dated Feb. 22, 2018	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2017	001-03034	10.30
10.21*+	Seventh Amendment to Exhibit 10.02 dated May 7, 2018	Xcel Energy Inc. Form 10-Q for the quarter ended June 30, 2018	001-03034	10.01
10.22*	Forward Sale Agreement, dated Nov. 7, 2018, between Xcel Energy Inc. and Morgan Stanley &Co., LLC	Xcel Energy Inc. Form 8-K dated Nov. 7, 2018	001-03034	10.01
10.23*	Amended and Restated 364-Day Term Loan Agreement dated as of Dec. 4, 2018 among Xcel Energy Inc., as Borrower, the several lenders from time to time parties thereto, and MUFG Bank, Ltd. as Administrative Agent.	Xcel Energy Inc. Form 8-K dated Dec. 4, 2018	001-03034	99.01
10.24*+	Xcel Energy Inc. Amended and Restated 2015 Omnibus Incentive Plan	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2018	001-03034	10.34
10.25*+	Form of Xcel Energy Inc. 2015 Omnibus Incentive Plan Award Agreement Terms and Conditions under the Xcel Energy Inc. Amended and Restated 2015 Omnibus Incentive Plan	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2018	001-03034	10.35
10.26*+	Stock Program for Non-Employee Directors of Xcel Energy Inc. as Amended and Restated on Dec. 12, 2017 under the 2015 Omnibus Incentive Plan	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2018	001-03034	10.36
10.27*+	Brett Carter's Sign-On Bonus Terms	Xcel Energy Inc. Form 10-Q for the quarter ended March 31, 2019	001-03034	10.01
10.28*	Third Amended and Restated Credit Agreement, dated as of June 7, 2019 among Xcel Energy Inc., as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A. and Barclays Bank Plc, as Syndication Agents, Wells Fargo Bank, National Association, MUFG Bank, Ltd., and Citibank, N.A., as Documentation Agents	Xcel Energy Inc. Form 8-K dated June 7, 2019	001-03034	99.01
10.29*	Forward Sale Agreement, dated Oct. 30, 2019, between Xcel Energy Inc. and Citibank, N.A.	Xcel Energy Inc. Form 8-K dated Oct. 30, 2019	001-03034	10.01
10.30*	Additional Forward Sale Agreement, dated Nov. 1, 2019 between Xcel Energy Inc. and Citibank, N.A.	Xcel Energy Inc. Form 8-K dated Oct. 30, 2019	001-03034	10.02
10.31*	364-Day Term Loan Agreement dated Dec. 3, 2019 among Xcel Energy Inc., as Borrower, the several lenders from time to time parties thereto, and Canadian Imperial Bank of Commerce, New York Branch, as Administrative Agent	Xcel Energy Inc. Form 8-K dated Dec. 3, 2019	001-03034	10.01
10.32+	Form of Xcel Energy Inc. 2015 Omnibus Incentive Plan Award Agreement Terms and Conditions under the Xcel Energy Inc. Amended and Restated 2015 Omnibus Incentive Plan			
NSP-Minnesota				
4.13*	Supplemental and Restated Trust Indenture, dated May 1, 1988, from NSP-Minnesota to Harris Trust and Savings Bank, as Trustee, providing for the issuance of First Mortgage Bonds, Supplemental Indentures between NSP-Minnesota and said Trustee	Xcel Energy Inc. Form S-3 dated April 18, 2018	001-03034	4(b)(3)
4.14*	Supplemental Trust Indenture dated June 1, 1995, creating $250 million principal amount of 7.125% First Mortgage Bonds, Series due 2025	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2017	001-03034	4.11
4.15*	Supplemental Trust Indenture dated March 1, 1998, creating $150 million principal amount of 6.5% First Mortgage Bonds, Series due 2028	Xcel Energy Inc. Form 10-K for the year ended Dec. 31, 2017	001-03034	4.12
4.16*	Supplemental Trust Indenture dated Aug. 1, 2000 (Assignment and Assumption of Trust Indenture)	NSP-Minnesota Form 10-12G dated Oct. 5, 2000	000-31709	4.51
4.17*	Indenture, dated July 1, 1999, between NSP-Minnesota and Norwest Bank Minnesota, NA, as Trustee, providing for the issuance of Sr. Debt Securities	Xcel Energy Inc. Form S-3 dated April 18, 2018	001-03034	4(b)(7)

4.18*	Supplemental Indenture, dated Aug. 18, 2000, supplemental to the Indenture dated July 1, 1999, among Xcel Energy, NSP-Minnesota and Wells Fargo Bank Minnesota, NA, as Trustee	NSP-Minnesota Form 10-12G dated Oct. 5, 2000	000-31709	4.63
4.19*	Supplemental Trust Indenture dated July 1, 2005 between NSP-Minnesota and BNY Midwest Trust Company, as successor Trustee, creating $250 million principal amount of 5.25% First Mortgage Bonds, Series due 2035	NSP-Minnesota Form 8-K dated July 14, 2005	001-31387	4.01
4.20*	Supplemental Trust Indenture dated May 1, 2006 between NSP-Minnesota and BNY Midwest Trust Company, as successor Trustee, creating $400 million principal amount of 6.25% First Mortgage Bonds, Series due 2036	NSP-Minnesota Form 8-K dated May 18, 2006	001-31387	4.01
4.21*	Supplemental Trust Indenture, dated June 1, 2007, between NSP-Minnesota and BNY Midwest Trust Company, as successor Trustee	NSP-Minnesota Form 8-K dated June 19, 2007	001-31387	4.01
4.22*	Supplemental Trust Indenture dated as of Nov. 1, 2009 between NSP-Minnesota and the Bank of New York Mellon Trust Co., NA, as successor Trustee, creating $300 million principal amount of 5.35% First Mortgage Bonds, Series due 2039	NSP-Minnesota Form 8-K dated Nov. 16, 2009	001-31387	4.01
4.23*	Supplemental Trust Indenture dated as of Aug. 1, 2010 between NSP-Minnesota and the Bank of New York Mellon Trust Company, NA, as successor Trustee, creating $250 million principal amount of 1.95% First Mortgage Bonds, Series due 2015 and $250 principal amount of 4.85% First Mortgage Bonds, Series due 2040	NSP-Minnesota Form 8-K dated Aug. 4, 2010	001-31387	4.01
4.24*	Supplemental Trust Indenture dated as of Aug. 1, 2012 between NSP-Minnesota and the Bank of New York Mellon Trust Company, NA, as successor Trustee, creating $300 million principal amount of 2.15% First Mortgage Bonds, Series due 2022 and $500 million principal amount of 3.40% First Mortgage Bonds, Series due 2042	NSP-Minnesota Form 8-K dated Aug. 13, 2012	001-31387	4.01
4.25*	Supplemental Trust Indenture dated as of May 1, 2013 between NSP-Minnesota and the Bank of New York Mellon Trust Company, N.A., as successor Trustee, creating $400 million principal amount of 2.60% First Mortgage Bonds, Series due 2023	NSP-Minnesota Form 8-K dated May 20, 2013	001-31387	4.01
4.26*	Supplemental Trust Indenture dated as of May 1, 2014 between NSP-Minnesota and the Bank of New York Mellon Trust Company, N.A., as successor Trustee, creating $300 million principal amount of 4.125% First Mortgage Bonds, Series due 2044	NSP-Minnesota Form 8-K dated May 13, 2014	001-31387	4.01
4.27*	Supplemental Trust Indenture dated as of Aug. 1, 2015 between NSP-Minnesota and the Bank of New York Mellon Company, N.A., as successor Trustee, creating $300 million principal amount of 2.20% First Mortgage Bonds, Series due 2020 and $300 million principal amount of 4.00% First Mortgage Bonds, Series due 2045	NSP-Minnesota Form 8-K dated Aug. 11, 2015	001-31387	4.01
4.28*	Supplemental Trust Indenture dated as of May 1, 2016 between NSP-Minnesota and the Bank of NY Mellon Trust Company, N.A., as successor Trustee, creating $350 million principal amount of 3.60% First Mortgage Bonds, Series due 2046	NSP-Minnesota Form 8-K dated May 31, 2016	001-31387	4.01
4.29*	Supplemental Trust Indenture dated as of Sept. 1, 2017 between NSP-Minnesota and The Bank of New York Mellon Trust Company, N.A., as successor Trustee, creating $600 million principal amount of 3.60% First Mortgage Bonds, Series due 2047	NSP-Minnesota Form 8-K dated Sept. 13, 2017	001-31387	4.01
4.30*	Supplemental Trust Indenture dated as of Sept. 1, 2019 between Northern States Power Company and the Bank of New York Mellon Trust Company, N.A., as successor Trustee, creating $600 million principal amount of 2.90% First Mortgage Bonds, Series due 2050	NSP-Minnesota Form 8-K dated Sept. 10, 2019	001-31387	4.01
10.33*	Restated Interchange Agreement dated Jan. 16, 2001 between NSP-Wisconsin and NSP-Minnesota	NSP-Wisconsin Form S-4 dated Jan. 21, 2004	333-112033	10.01
10.34*	Third Amended and Restated Credit Agreement, dated as of June 7, 2019 among NSP-Minnesota, as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A. and Barclays Bank Plc, as Syndication Agents, Wells Fargo Bank, National Association, MUFG Bank, Ltd., and Citibank, N.A., as Documentation Agents	Xcel Energy Inc. Form 8-K dated June 7, 2019	001-03034	99.02
NSP-Wisconsin				
4.31*	Supplemental and Restated Trust Indenture, dated March 1, 1991, between NSP-Wisconsin and First Wisconsin Trust Company, providing for the issuance of First Mortgage Bonds	Xcel Energy Inc. Form S-3 dated April 18, 2018	001-03034	4(c)(3)
4.32*	Trust Indenture dated Sept. 1, 2000 between NSP-Wisconsin and Firstar Bank, NA as Trustee	NSP-Wisconsin Form 8-K dated Sept. 25, 2000	001-03140	4.01
4.33*	Supplemental Trust Indenture dated as of Sept. 1, 2003 between NSP-Wisconsin and U.S. Bank National Association, supplementing indentures dated April 1, 1947 and March 1, 1991	Xcel Energy Inc Form 10-Q for the quarter ended Sept. 30, 2003	001-03034	4.05
4.34*	Supplemental Trust Indenture dated as of Sept. 1, 2008 between NSP-Wisconsin and U.S. Bank National Association, as successor Trustee, creating $200 million principal amount of 6.375% First Mortgage Bonds, Series due 2038	NSP-Wisconsin Form 8-K dated Sept. 3, 2008	001-03140	4.01
4.35*	Supplemental Trust Indenture dated as of Oct. 1, 2012 between NSP-Wisconsin and U.S. Bank National Association, as successor Trustee, creating $100 million principal amount of 3.70% First Mortgage Bonds, Series due 2042	NSP-Wisconsin Form 8-K dated Oct. 10, 2012	001-03140	4.01
4.36*	Supplemental Trust Indenture dated as of June 1, 2014 between NSP-Wisconsin and U.S. Bank National Association, as successor Trustee, creating $100 million principal amount of 3.30% First Mortgage Bonds, Series due 2024	NSP-Wisconsin Form 8-K dated June 23, 2014	001-03140	4.01
4.37*	Supplemental Trust Indenture dated as of Nov 1, 2017 between NSP-Wisconsin and U.S. Bank National Association, as successor Trustee, creating $100 million principal amount of 3.75% First Mortgage Bonds, Series due 2047	NSP-Wisconsin Form 8-K dated Dec. 4, 2017	001-03140	4.01
4.38*	Supplemental Indenture dated as of Sept. 1, 2018 between NSP-Wisconsin and U.S. Bank National Association, as successor Trustee, creating $200 million principal amount of 4.20% First Mortgage Bonds, Series due 2048	NSP-Wisconsin to Form 8-K dated Sept. 12, 2018	001-03034	4.01
10.35*	Restated Interchange Agreement dated Jan. 16, 2001 between NSP-Wisconsin and NSP-Minnesota	NSP-Wisconsin Form S-4 dated Jan. 21, 2004	333-112033	10.01

10.36*	Third Amended and Restated Credit Agreement, dated as of June 7, 2019 among NSP-Wisconsin, as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A. and Barclays Bank Plc, as Syndication Agents, Wells Fargo Bank, National Association, MUFG Bank, Ltd., and Citibank, N.A., as Documentation Agents	Xcel Energy Inc. Form 8-K dated June 7, 2019	001-03034	99.05
PSCo				
4.39*	Indenture, dated as of Oct. 1, 1993 between PSCo and Morgan Guaranty Trust Company of New York, as Trustee, providing for the issuance of First Collateral Trust Bonds	Xcel Energy Inc. Form S-3 dated April 18, 2018	001-03034	4(d)(3)
4.40*	Indenture dated July 1, 1999, between PSCo and The Bank of New York, providing for the issuance of Senior Debt Securities and First Supplemental Indenture dated July 14, 1999 between PSCo and the Bank of New York	PSCo Form 8-K dated July 13, 1999	001-03280	4.1 4.2
4.41*	Supplemental Indenture, dated Aug. 1, 2007 between PSCo and U.S. Bank Trust National Association, as successor Trustee	PSCo Form 8-K dated Aug. 8, 2007	001-03280	4.01
4.42*	Supplemental Indenture dated as of Aug. 1, 2008 between PSCo and U.S. Bank Trust National Association, as successor Trustee, creating $300 million principal amount of 5.80% First Mortgage Bonds, Series due 2018 and $300 million principal amount of 6.50% First Mortgage Bonds, Series due 2038	PSCo Form 8-K dated Aug. 6, 2008	001-03280	4.01
4.43*	Supplemental Indenture dated as of May 1, 2009 between PSCo and U.S. Bank Trust National Association, as successor Trustee, creating $400 million principal amount of 5.125% First Mortgage Bonds, Series due 2019	PSCo Form 8-K dated May 28, 2009	001-03280	4.01
4.44*	Supplemental Indenture dated as of Nov. 1, 2010 between PSCo and U.S. Bank National Association, as successor Trustee, creating $400 million principal amount of 3.20% First Mortgage Bonds, Series due 2020	PSCo Form 8-K dated Nov. 8, 2010	001-03280	4.01
4.45*	Supplemental Indenture dated as of Aug. 1, 2011 between PSCo and U.S. Bank National Association, as successor Trustee, creating $250 million principal amount of 4.75% First Mortgage Bonds, Series due 2041	PSCo Form 8-K dated Aug. 9, 2011	001-03280	4.01
4.46*	Supplemental Indenture dated as of Sept. 1, 2012 between PSCo and U.S. Bank National Association, as successor Trustee, creating $300 million principal amount of 2.25% First Mortgage Bonds, Series due 2022 and $500 million principal amount of 3.60% First Mortgage Bonds, Series due 2042	PSCo Form 8-K dated Sept. 11, 2012	001-03280	4.01
4.47*	Supplemental Indenture dated as of March 1, 2013 between PSCo and U.S. Bank National Association, as successor Trustee, creating $250 million principal amount of 2.50% First Mortgage Bonds, Series due 2023 and $250 million principal amount of 3.95% First Mortgage Bonds, Series due 2043	PSCo Form 8-K dated March 26, 2013	001-03280	4.01
4.48*	Supplemental Indenture dated as of March 1, 2014 between PSCo and U.S. Bank National Association, as successor Trustee, creating $300 million principal amount of 4.30% First Mortgage Bonds, Series due 2044	PSCo Form 8-K dated March 10, 2014	001-03280	4.01
4.49*	Supplemental Indenture dated as of May 1, 2015 between PSCo and U.S. Bank National Association, as successor Trustee, creating $250 million principal amount of 2.90% First Mortgage Bonds, Series due 2025	PSCo Form 8-K dated May 12, 2015	001-03280	4.01
4.50*	Supplemental Indenture dated as of June 1, 2016 between PSCo and U.S. Bank National Association, as successor Trustee, creating $250 million principal amount of 3.55% First Mortgage Bonds, Series due 2046	PSCo Form 8-K dated June 13, 2016	001-03280	4.01
4.51*	Supplemental Indenture dated as of June 1, 2017 between PSCo and U.S. Bank National Association, as successor Trustee, creating $400 million principal amount of 3.80% First Mortgage Bonds, Series due 2047	PSCo Form 8-K dated June 19, 2017	001-03280	4.01
4.52*	Supplemental Indenture dated as of June 1, 2018 between PSCo and U.S. Bank National Association, as successor Trustee, creating $350 million principal amount of 3.70% First Mortgage Bonds, Series due 2028, and $350 million principal amount of 4.10% First Mortgage Bonds, Series due 2048	PSCo Form 8-K dated June 21, 2018	001-03280	4.01
4.53*	Supplemental Indenture dated as of March 1, 2019 between PSCo and U.S. Bank National Association, as successor Trustee, creating $400 million principal amount of 4.05% First Mortgage Bonds, Series due 2049	PSCo Form 8-K dated March 13, 2019	001-03280	4.01
4.54*	Supplemental Indenture dated as of Aug. 1, 2019 between PSCo and U.S. Bank National Association, as successor Trustee, creating $550 million principal amount of 3.20% First Mortgage Bonds, Series due 2050	PSCo Form 8-K dated August 13, 2019	001-03280	4.01
10.37*	Proposed Settlement Agreement, excerpts, as filed with the CPUC	Xcel Energy Inc. Form 8-K dated Dec. 3, 2004	001-03034	99.02
10.38*	Third Amended and Restated Credit Agreement, dated as of June 7, 2019 among PSCo, as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A. and Barclays Bank Plc, as Syndication Agents, Wells Fargo Bank, National Association, MUFG Bank, Ltd., and Citibank, N.A., as Documentation Agents	Xcel Energy Inc. Form 8-K dated June 7, 2019	001-03034	99.03
SPS				
4.55*	Indenture dated Feb. 1, 1999 between SPS and the Chase Manhattan Bank	SPS Form 8-K dated Feb. 25, 1999	001-03789	99.2
4.56*	Supplemental Indenture dated Oct. 1, 2003 between SPS and JPMorgan Chase Bank, as successor Trustee, creating $100 million principal amount of Series C and Series D Notes, 6% due 2033	Xcel Energy Inc. Form 10-Q for the quarter ended Sept. 30, 2003	001-03034	4.04
4.57*	Supplemental Indenture dated Oct. 1, 2006 between SPS and the Bank of New York, as successor Trustee, creating $200 million principal amount of 5.6% Series E Notes due 2016 and $250 million principal amount of 6% Series F Notes due 2036	SPS Form 8-K dated Oct. 3, 2006	001-03789	4.01
4.58*	Indenture dated as of Aug. 1, 2011 between SPS and U.S. Bank National Association, as Trustee	SPS Form 8-K dated Aug. 10, 2011	001-03789	4.01
4.59*	Supplemental Indenture dated as of Aug. 3, 2011 between SPS and U.S. Bank National Association, as Trustee, creating $200 million principal amount of 4.50% First Mortgage Bonds, Series due 2041	SPS Form 8-K dated Aug. 10, 2011	001-03789	4.02
4.60*	Supplemental Indenture dated as of June 1, 2014 between SPS and U.S. Bank National Association, as Trustee, creating $150 million principal amount of 3.30% First Mortgage Bonds, Series due 2024	SPS Form 8-K dated June 9, 2014	001-03789	4.02
4.61*	Supplemental Indenture dated as of Aug. 1, 2016 between SPS and U.S. Bank National Association, as Trustee, creating $300 million principal amount of 3.40% First Mortgage Bonds, Series due 2046	SPS Form 8-K dated Aug. 12, 2016	001-03789	4.02
4.62*	Supplemental Indenture dated as of Aug. 1, 2017 between SPS and U.S. Bank National Association, as Trustee, creating $450 million principal amount of 3.70% First Mortgage Bonds, Series due 2047	SPS Form 8-K dated Aug 9. 2017	001-03789	4.02
4.63*	Supplemental Indenture dated as of Oct. 1, 2018 between SPS and U.S. Bank National Association, as Trustee, creating $300 million principal amount of 4.40% First Mortgage Bonds, Series due 2048	SPS Form 8-K dated Nov. 5, 2018	001-03789	4.02

4.64*	Supplemental Indenture dated as of June 1, 2019 between SPS and U.S. Bank National Association, as Trustee, creating $300 million principal amount of 3.75% First Mortgage Bonds, Series due 2049	SPS Form 8-K dated June 18, 2019	001-03789	4.02
10.39*	Third Amended and Restated Credit Agreement, dated as of June 7, 2019 among SPS, as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A. and Barclays Bank Plc, as Syndication Agents, Wells Fargo Bank, National Association, MUFG Bank, Ltd., and Citibank, N.A., as Documentation Agents	Xcel Energy Inc. Form 8-K dated June 7, 2019	001-03034	99.04
Xcel Energy Inc.				
21.01	Subsidiaries of Xcel Energy Inc.			
23.01	Consent of Independent Registered Public Accounting Firm			
24.01	Powers of Attorney			
31.01	Principal Executive Officer's certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002			
31.02	Principal Financial Officer's certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002			
32.01	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002			
101.INS	XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document			
101.SCH	XBRL Schema			
101.CAL	XBRL Calculation			
101.DEF	XBRL Definition			
101.LAB	XBRL Label			
101.PRE	XBRL Presentation			
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101)			

SCHEDULE I

XCEL ENERGY INC.
CONDENSED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(amounts in millions, except per share data)

	Year Ended Dec. 31		
	2019	2018	2017
Income			
Equity earnings of subsidiaries	$ 1,505	$ 1,393	$ 1,263
Total income	1,505	1,393	1,263
Expenses and other deductions			
Operating expenses	23	24	30
Other income	(9)	(1)	(6)
Interest charges and financing costs	173	149	128
Total expenses and other deductions	187	172	152
Income before income taxes	1,318	1,221	1,111
Income tax benefit	(54)	(40)	(37)
Net income	$ 1,372	$ 1,261	$ 1,148
Other Comprehensive Income			
Pension and retiree medical benefits, net of tax of $1, $1 and $3, respectively	$ 3	$ 3	$ 4
Derivative instruments, net of tax of $(7), $(1) and $2, respectively	(20)	(2)	3
Other comprehensive income (loss)	(17)	1	7
Comprehensive income	$ 1,355	$ 1,262	$ 1,155
Weighted average common shares outstanding:			
Basic	519	511	509
Diluted	520	511	509
Earnings per average common share:			
Basic	$ 2.64	$ 2.47	$ 2.26
Diluted	2.64	2.47	2.25

See Notes to Condensed Financial Statements

XCEL ENERGY INC.
CONDENSED STATEMENTS OF CASH FLOWS
(amounts in millions)

	Year Ended Dec. 31		
	2019	2018	2017
Operating activities			
Net cash provided by operating activities	$ 1,389	$ 1,210	$ 1,208
Investing activities			
Capital contributions to subsidiaries	(1,594)	(809)	(849)
Investments in the utility money pool	(1,054)	(2,578)	(1,258)
Return of investments in the utility money pool	1,093	2,493	1,173
Net cash used in investing activities	(1,555)	(894)	(934)
Financing activities			
Proceeds from (repayment of) short-term borrowings, net	12	(295)	715
Proceeds from issuance of long-term debt	1,120	492	—
Repayment of long-term debt	(550)	—	(250)
Proceeds from issuance of common stock	458	230	—
Repurchase of common stock	—	(1)	(3)
Dividends paid	(791)	(730)	(721)
Other	(14)	(12)	(14)
Net cash (used in) provided by financing activities	235	(316)	(273)
Net change in cash and cash equivalents	69	—	1
Cash and cash equivalents at beginning of period	1	1	—
Cash and cash equivalents at end of period	$ 70	$ 1	$ 1

See Notes to Condensed Financial Statements

XCEL ENERGY INC.
CONDENSED BALANCE SHEETS
(amounts in millions)

	Dec. 31	
	2019	2018
Assets		
Cash and cash equivalents	$ 70	$ 1
Accounts receivable from subsidiaries	370	309
Other current assets	12	1
Total current assets	452	311
Investment in subsidiaries	17,443	15,965
Other assets	60	44
Total other assets	17,503	16,009
Total assets	$ 17,955	$ 16,320
Liabilities and Equity		
Dividends payable	212	195
Short-term debt	500	488
Other current liabilities	33	10
Total current liabilities	745	693
Other liabilities	23	32
Total other liabilities	23	32
Commitments and contingencies		
Capitalization		
Long-term debt	3,948	3,373
Common stockholders' equity	13,239	12,222
Total capitalization	17,187	15,595
Total liabilities and equity	$ 17,955	$ 16,320

See Notes to Condensed Financial Statements

Notes to Condensed Financial Statements

Incorporated by reference are Xcel Energy's consolidated statements of common stockholders' equity and other comprehensive income in Part II, Item 8.

Basis of Presentation — The condensed financial information of Xcel Energy Inc. is presented to comply with Rule 12-04 of Regulation S-X. Xcel Energy Inc.'s investments in subsidiaries are presented under the equity method of accounting. Under this method, the assets and liabilities of subsidiaries are not consolidated. The investments in net assets of the subsidiaries are recorded in the balance sheets. The income from operations of the subsidiaries is reported on a net basis as equity in income of subsidiaries.

As a holding company with no business operations, Xcel Energy Inc.'s assets consist primarily of investments in its utility subsidiaries. Xcel Energy Inc.'s material cash inflows are only from dividends and other payments received from its utility subsidiaries and the proceeds raised from the sale of debt and equity securities. The ability of its utility subsidiaries to make dividend and other payments is subject to the availability of funds after taking into account their respective funding requirements, the terms of their respective indebtedness, the regulations of the FERC under the Federal Power Act, and applicable state laws. Management does not expect maintaining these requirements to have an impact on Xcel Energy Inc.'s ability to pay dividends at the current level in the foreseeable future. Each of its utility subsidiaries, however, is legally distinct and has no obligation, contingent or otherwise, to make funds available to Xcel Energy Inc.

Guarantees and Indemnifications

Xcel Energy Inc. provides guarantees and bond indemnities under specified agreements or transactions, which guarantee payment or performance. Xcel Energy Inc.'s exposure is based upon the net liability of the relevant subsidiary under the specified agreements or transactions. Most of the guarantees and bond indemnities issued by Xcel Energy Inc. limit the exposure to a maximum stated amount. As of Dec. 31, 2019 and 2018, Xcel Energy Inc. had no assets held as collateral related to guarantees, bond indemnities and indemnification agreements.

Guarantees and bond indemnities issued and outstanding as of Dec. 31, 2019:

(Millions of Dollars)	Guarantor	Guarantee Amount	Current Exposure	Triggering Event
Guarantee of loan for Hiawatha Collegiate High School [(a)]	Xcel Energy Inc.	$ 1.0	—	[(c)]
Guarantee performance and payment of surety bonds for Xcel Energy Inc.'s utility subsidiaries [(b)]	Xcel Energy Inc.	60.4	[(e)]	[(d)]

(a) The term of this guarantee expires the earlier of 2024 or full repayment of the loan.

(b) The surety bonds primarily relate to workers compensation benefits and utility projects. The workers compensation bonds are renewed annually and the project based bonds expire in conjunction with the completion of the related projects.

(c) Nonperformance and/or nonpayment.

(d) Per the indemnity agreement between Xcel Energy Inc. and the various surety companies, surety companies have the discretion to demand that collateral be posted.

(e) Due to the magnitude of projects associated with the surety bonds, the total current exposure of this indemnification cannot be determined. Xcel Energy Inc. believes the exposure to be significantly less than the total amount of the outstanding bonds.

Indemnification Agreements

Xcel Energy Inc. provides indemnifications through contracts entered into in the normal course of business. Indemnifications are primarily against adverse litigation outcomes in connection with underwriting agreements, breaches of representations and warranties, including corporate existence, transaction authorization and certain income tax matters. Obligations under these agreements may be limited in terms of duration or amount. Maximum future payments under these indemnifications cannot be reasonably estimated as the dollar amounts are often not explicitly stated.

Related Party Transactions — Xcel Energy Inc. presents related party receivables net of payables. Accounts receivable and payable with affiliates at Dec. 31:

	2019		2018	
(Millions of Dollars)	Accounts Receivable	Accounts Payable	Accounts Receivable	Accounts Payable
NSP-Minnesota	$ 60	$ —	$ 117	$ —
NSP-Wisconsin	17	—	3	—
PSCo	78	—	29	—
SPS	47	—	39	—
Xcel Energy Services Inc.	112	—	96	—
Xcel Energy Ventures Inc.	25	—	13	—
Other subsidiaries of Xcel Energy Inc.	31	—	12	—
	$ 370	$ —	$ 309	$ —

Dividends — Cash dividends paid to Xcel Energy Inc. by its subsidiaries were $2,987 million, $1,097 million and $1,063 million for the years ended Dec. 31, 2019, 2018 and 2017, respectively. These cash receipts are included in operating cash flows of the condensed statements of cash flows.

Money Pool — FERC approval was received to establish a utility money pool arrangement with the utility subsidiaries, subject to receipt of required state regulatory approvals. The utility money pool allows for short-term investments in and borrowings between the utility subsidiaries. Xcel Energy Inc. may make investments in the utility subsidiaries at market-based interest rates; however, the money pool arrangement does not allow the utility subsidiaries to make investments in Xcel Energy Inc.

Money pool lending for Xcel Energy Inc.:

(Amounts in Millions, Except Interest Rates)	Three Months Ended Dec. 31, 2019
Loan outstanding at period end	$ 39
Average loan outstanding	35
Maximum loan outstanding	125
Weighted average interest rate, computed on a daily basis	1.67%
Weighted average interest rate at end of period	1.63%
Money pool interest income	1.47%

(Amounts in Millions, Except Interest Rates)	Year Ended Dec. 31, 2019	Year Ended Dec. 31, 2018	Year Ended Dec. 31, 2017
Loan outstanding at period end	$ 39	$ —	$ 85
Average loan outstanding	47	71	38
Maximum loan outstanding	250	243	226
Weighted average interest rate, computed on a daily basis	2.15%	1.95%	1.13%
Weighted average interest rate at end of period	1.63%	N/A	1.18
Money pool interest income	$ 1.0	$ 1.4	$ 0.4

See notes to the consolidated financial statements in Part II, Item 8.

SCHEDULE II

Xcel Energy Inc. and Subsidiaries Valuation and Qualifying Accounts Years Ended Dec. 31

	Allowance for bad debts			NOL and tax credit valuation allowances		
(Millions of Dollars)	2019	2018	2017	2019	2018	2017
Balance at Jan. 1	$ 55	$ 52	$ 51	$ 79	$ 77	$ 58
Additions charged to costs and expenses	42	42	39	9	7	9
Additions charged to other accounts	16 [(a)]	11 [(a)]	10 [(a)]	—	—	22 [(c)]
Deductions from reserves	(58) [(b)]	(50) [(b)]	(48) [(b)]	(21) [(e)]	(5) [(e)]	(12) [(d)]
Balance at Dec. 31	$ 55	$ 55	$ 52	$ 67	$ 79	$ 77

(a) Recovery of amounts previously written off.

(b) Deductions related primarily to bad debt write-offs.

(c) Accrual of valuation allowances for North Dakota ITC, net of federal income tax benefit, that is offset to a regulatory liability and includes $14 million expense related to the revaluation of federal benefit as a result of the TCJA.

(d) Primarily the reductions to valuation allowances for North Dakota ITC carryforwards, net of federal benefit, primarily due to a consolidated adjustment to the regulatory liability accrual referenced above; the change includes $4 million of reduced expense related to the revaluation of federal benefit as a result of TCJA.

(e) Primarily the reductions to valuation allowances due to additional NOLs and tax credits now forecasted to be used prior to expiration.

ITEM 16 — FORM 10-K SUMMARY

None.

Signatures

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this annual report to be signed on its behalf by the undersigned thereunto duly authorized.

		XCEL ENERGY INC.
Feb. 21, 2020	By:	/s/ ROBERT C. FRENZEL
		Robert C. Frenzel
		Executive Vice President, Chief Financial Officer
		(Principal Financial Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities on the date indicated above.

	/s/ BEN FOWKE Ben Fowke	Chairman, President, Chief Executive Officer and Director (Principal Executive Officer)
	/s/ ROBERT C. FRENZEL Robert C. Frenzel	Executive Vice President, Chief Financial Officer (Principal Financial Officer)
	/s/ JEFFREY S. SAVAGE Jeffrey S. Savage	Senior Vice President, Controller (Principal Accounting Officer)
*	Lynn Casey	Director
*	Richard K. Davis	Director
*	Richard T. O’Brien	Director
*	David K. Owens	Director
*	Christopher J. Policinski	Director
*	James Prokopanko	Director
*	A. Patricia Sampson	Director
*	James J. Sheppard	Director
*	David A. Westerlund	Director
*	Kim Williams	Director
*	Timothy V. Wolf	Director
*	Daniel Yohannes	Director
*By:	/s/ ROBERT C. FRENZEL Robert C. Frenzel	Attorney-in-Fact